REVIEW

Australian Energy Market Commission

DRAFT REPORT

Frequency Control Frameworks Review

20 March 2018

Submissions due 24 April 2018. Reference: EPR0059
Draft report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: EPR0059

Citation

AEMC 2018, Frequency Control Frameworks Review, Draft report, 20 March 2018, Sydney

About the AEMC

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

Executive summary

The *Frequency control frameworks review* forms the next phase of work the Australian Energy Market Commission (AEMC or Commission) is undertaking to address the security issues arising from the current market transformation.

To keep the lights on, the power system needs to be:

- secure – that is, able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator
- reliable – that is, with enough generation, demand-side and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

The Australian Energy Market Operator (AEMO) is responsible for maintaining power system security in the National Electricity Market (NEM). In addition to procuring services for the system such as frequency control, it has a number of regulatory tools through which it can intervene in the market to make sure the system remains in a secure state. By contrast, reliability is delivered in the NEM through efficient investment, retirement and operational decisions by market participants that are underpinned by various market structures. This is why the reliability framework in the NEM is referred to as being primarily market-based. This review does not address reliability given the frameworks through which reliability outcomes are delivered are different to those relevant for the delivery of security outcomes. The Commission is considering reliability through its *Reliability frameworks review*.

The *Frequency control frameworks review* forms part of the AEMC's ongoing system security work program, which comprises a number of rule changes and reviews that seek to address risks to power system security caused by the transition from conventional generation powered by coal, gas and hydro to generation powered by renewable sources such as wind and solar. An overview of the AEMC's system security work program is provided in Figure 2 at the end of this executive summary.

Specifically, the *Frequency control frameworks review* considers what changes may be required to the regulatory and market frameworks to maintain effective frequency control arising from, and harness the opportunities presented by, the changing generation mix in the NEM. It also provides a vehicle through which the AEMC can progress, and seek stakeholder views on, those recommendations made in relation to frequency control in the final reports of the AEMC's *System security market frameworks review* and the *Distribution market model* project[1] aimed at:

- addressing current concerns with frequency performance in the NEM

1 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review and http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model.

- exploring how best to integrate faster frequency control services offered by new technologies into the current regulatory and market arrangements
- removing barriers to distributed energy resources participating in system security frameworks.

These challenges and opportunities have been recognised by a number of other organisations, including AEMO, the Finkel Review Panel and Energy Networks Australia.[2]

What is frequency control and why is it important?

The power system is in a secure operating state if it is capable of withstanding a credible contingency event, which is defined as an event that AEMO considers to be reasonably possible in the surrounding circumstances. Examples of credible contingency events include the failure of a single network element or generating unit. System security events are caused by sudden equipment failure (often associated with extreme weather or bushfires) that may result in the system operating outside of defined technical limits.

One of these technical limits is frequency. In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hertz (Hz).

The frequency of the power system varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise, and vice versa. In the majority of situations, the changes in supply and demand are such that the corresponding variations in frequency are very small. However, sometimes, large generating units and transmission lines may trip unexpectedly and stop producing or transmitting electricity. These events tend to result in larger changes in system frequency and more significant impacts on the safety and reliability of the power system, for example as was experienced in the system black event in South Australia on 28 September 2016. Controlling frequency is therefore critically important.

The National Electricity Rules (NER) set up market and regulatory frameworks by which AEMO, as the body responsible for maintaining power system security, can manage frequency levels. Effective control of power system frequency requires the coordination of power system inertia[3] and the provision of a range of frequency control services. These services are used to raise system frequency if it has fallen (by increasing generation or reducing load) and to lower system frequency if it has risen

2 Specifically, through AEMO's Future Power System Security work program, AEMO's reference paper on power system requirements, the Finkel Panel's *Independent review into the future security of the national electricity market*, and the Energy Networks Australia/CSIRO *Electricity network transformation roadmap*.

3 Inertia is a measure of the ability of the system to resist changes in frequency due to sudden changes in supply and demand. It is naturally provided by synchronous generators such as coal, hydro and gas-fired power stations.

(by decreasing generation or increasing load). Frequency control services are intended to work together to maintain a steady power system frequency close to 50Hz during normal operation, and to stabilise and restore the power system frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

Drivers of change

The electricity industry in Australia is undergoing fundamental change as newer types of electricity generation, such as wind and solar, connect and conventional forms of electricity generation, such as coal, retire. In addition, a formerly passive demand side is becoming increasingly engaged in energy markets through the uptake of new technologies and services, such as solar PV, storage and demand response. These technologies are greatly expanding the choices that consumers have to manage their energy needs. It is also changing the way in which these consumers draw electricity from, and export electricity to, the broader power system.

This transformation has potential implications for the management of power system frequency that need to be considered. Specifically, an increased potential for imbalances between electricity demand and supply is driven by:

- a **reduction in frequency control capability**, as a result of:
  - the exit of traditional providers of inertia and frequency control services
  - a reduction in the frequency responsiveness of generators during normal operation
- **increased variability and unpredictability of supply and demand**, which creates challenges for AEMO's forecasting and dispatch processes, as a result of:
  - increasingly rapid changes in supply and demand from variable renewable generation and the operation of distributed energy resources due to changing weather conditions or changes in their operation
  - a lack of visibility of the operation of distributed energy resources

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

Further, the existing frequency control frameworks were largely established when the technical characteristics and capabilities of the generation mix were very different. As the generation fleet changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve. There may now be opportunities for the new energy technologies being connected to contribute in more effective ways to support power system security, including by providing frequency control services.

Purpose of this draft report

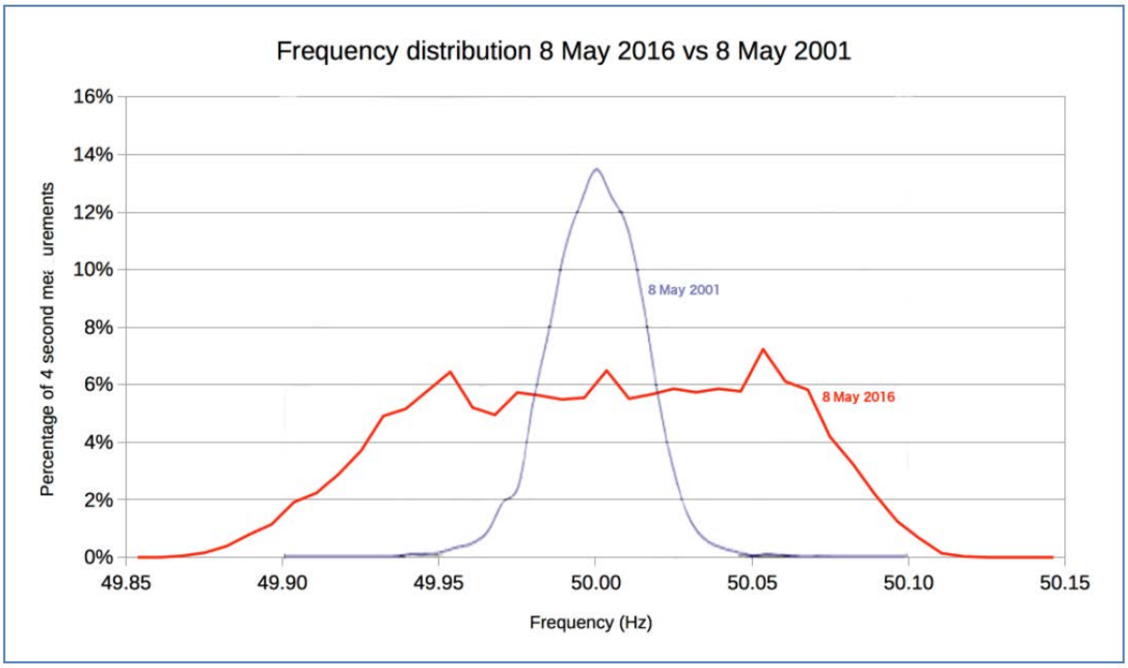
This draft report represents the second stage of public consultation on the review. Its purpose is to set out the AEMC's analysis of the market and regulatory frameworks for frequency control in the NEM, and provide draft recommendations on ways in which these frameworks could be improved to enhance their effectiveness. Table 1 at the end of this executive summary provides an overview of all the draft recommendations, the issues they are seeking to address, and the relevant section of the draft report where they are discussed.

As the NEM continues to change, there is likely to be a growing need to re-evaluate the design of the current frequency control frameworks. However, any changes to these frameworks are not without costs. While there is some evidence that the current frameworks are limiting the efficiency of market outcomes, moving immediately to a completely new set of frequency control arrangements may not be appropriate in the current market environment. The AEMC has therefore divided its assessment of proposed changes to frequency control frameworks into two categories that reflect a prioritisation of the need for changes to be determined and implemented over time.

Immediate priorities

Frequency performance under normal operating conditions has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band (shown in Figure 1 below). The Commission considers that this degradation has near term implications for power system security and should be addressed as a priority.

Figure 1 Degradation of frequency control performance



This draft report sets out the consequences of deteriorating frequency control, the drivers of the degradation of frequency control performance, an assessment of the materiality of the degradation, possible options to address the degradation and the AEMC's draft recommendations on which of those options are most likely to further the National Electricity Objective.

The draft report also sets out the AEMC's analysis and draft recommendations in relation to the reporting of frequency control performance and frequency control ancillary service (FCAS) market outcomes in the NEM, and AEMO's supply/demand forecasting arrangements.

Emerging issues

Currently, market participant offers for energy and FCAS are co-optimised through the NEM dispatch process to determine the lowest price outcome, subject to constraints. Since establishment in 2001, the existing frameworks for procuring frequency control services have proved effective in optimising the dispatch of FCAS sources in real time to provide efficient market outcomes. However, as the generation mix changes, there is likely to be a growing need to re-evaluate the current arrangements for the procurement on these services. New approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies.

This draft report sets out the AEMC's analysis and draft recommendations in relation to the participation of distributed energy resources in system security frameworks. Specifically, it explores whether there are any unnecessary regulatory barriers that may prevent distributed energy resources providing FCAS or other system security services, and provides draft recommendations on ways in which these barriers could be addressed as the uptake of distributed energy resources increases. As set out in the final report of the *Distribution market model* project, the AEMC envisages a future where consumers have the ability to maximise the value of their investment in distributed energy resources by enabling them to, if they choose, utilise and sell the full range of services that the distributed energy resource is capable of providing, given any technical constraints.

This draft report also explores the range of market and regulatory approaches to the management of power system frequency that exist or could exist in future, a longer-term consideration of the appropriateness of the existing FCAS market arrangements to meet emerging system needs, and ways to facilitate co-optimisation between energy, FCAS and other system characteristics such as inertia.

Stakeholder consultation

The AEMC invites submissions on any aspect of this draft report by 24 April 2018.

Stakeholder input on this paper will further inform the AEMC's analysis of the issues and the development of final recommendations, which will be reflected in a final report in July 2018.

The AEMC also welcomes individual meetings with interested stakeholders. Those wishing to meet with the AEMC should contact Claire Richards on (02) 8296 7878 or claire.richards@aemc.gov.au.

Figure 2 Overview of the AEMC's system security work program

Table 1 Summary of draft recommendations

No.	Identified issue	Draft recommendation	Relevant section of draft report
Immediate priorities			
1	AEMO's procedure for determining how regulating FCAS costs are recovered and from whom (the "causer pays procedure") does not transparently and accurately map the allocation of costs to actions that create the need for the regulation services.	(a) That AEMO investigate whether: (i) the average period used for calculation of contribution factors could be aligned with the period over which the costs are incurred, preferably on a five minute basis (ii) the ten business day notice period between publishing and applying contribution factors is appropriate or could be removed. (b) That AEMO clarify how the causer pays procedure works and the specific variable that generator performance is measured against (i.e. frequency indicator or frequency) such that contribution factors can be calculated in real time by market participants.	Chapter 5
2	Frequency control performance under normal operating conditions has been deteriorating in recent times, largely as a result of generators reducing or removing their provision of a voluntary 'governor response'[4] to minor frequency deviations.	That the providers of a primary regulating response should be remunerated for the costs of providing the service, in particular where the opportunity costs of maintaining the capacity to provide the service (e.g. maintaining headroom to be able to increase output) are likely to be high. The implementation of one of the following two options is likely to build on the existing market frameworks and support improved frequency control during normal operation: • provision of a primary regulating response through the existing regulating FCAS markets	Chapter 5

[4] A governor is a device that regulates the speed of a machine, such as a generating unit. A governor can be tuned to automatically to respond to help control power system frequency changes.

No.	Identified issue	Draft recommendation	Relevant section of draft report
		• changes to the causer pays arrangements to facilitate the provision of incentive payments for primary frequency response during normal operation. Further work is required to investigate and describe the potential arrangements for the implementation of these options, and the associated costs and benefits of these arrangements.	
3	There is currently a lack of transparency regarding the frequency performance of the power system and the performance of FCAS markets.	That a rule change request be submitted to amend the NER to require: (a) AEMO to monitor, and publish reports on, frequency outcomes with respect to the requirements of the frequency operating standard (b) AEMO to provide information to the AER on the performance of FCAS markets and for the AER to monitor, and report on, the performance of FCAS markets.	Section 6.1
Emerging needs			
4	There is an absence of market participant categories in the NER that permit distributed energy resources capable of exporting electricity to the network to be aggregated to provide market ancillary services (e.g. FCAS).	That a rule change request be submitted to enable: (a) Market Ancillary Service Providers to classify small generating units as ancillary service generating units for the purposes of offering market ancillary services (b) Small Generation Aggregators to classify small generating units as ancillary service generating units for the purposes of offering market ancillary services. These changes may also require changes to AEMO's market ancillary service specification (MASS).[5]	Section 7.4

5 The MASS sets a detailed description of each kind of market ancillary service (e.g. FCAS) and how a market participant's performance is measured and verified when providing these market ancillary services.

No.	Identified issue	Draft recommendation	Relevant section of draft report
5	The current MASS potentially presents a barrier to the provision of market ancillary services by distributed energy resources, and may be resulting in an underutilisation of market ancillary services provided by newer technologies.	That: (a) AEMO provide more information regarding particular service characteristics that may be able to be trialled under the MASS (b) undertake trials of distributed energy resources providing FCAS that consider various technology types and different options for metering and verification, with a view to sharing the outcomes of the trials with relevant stakeholders (c) conduct a broader review of the MASS and consider how the value of distributed energy resources can be appropriately recognised.	Section 7.5
6	The current application of the connection arrangements for distributed energy resources, and Australian Standard 4777, may be hindering the ability of distributed energy resources to provide system security services.	That Energy Networks Australia, in developing its national connection guidelines, provide guidance on: • what capability is reasonable to require from distributed energy resources as a condition of connection in order to address the impact of that connection • the expected application of AS 4777 to different connection types and sizes • the technical justification for any mandated services • the extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services. The Commission encourages stakeholders to provide input into the development of these guidelines.	Section 7.6
7	Distributed energy resources providing system security services are likely to have an impact on local network conditions. Similarly, local network conditions will likely affect the ability	That: (a) AEMO, in conjunction with DNSPs, conduct trials of aggregated distributed energy resources providing FCAS to assess their ability to provide services under different network conditions, and how the provision of those services affect the local network and the power	Section 7.7

No.	Identified issue	Draft recommendation	Relevant section of draft report
	for distributed energy resources to provide system security services.	system more broadly (b) DNSPs and aggregators share information about the types of network conditions that may constrain the operation of distributed energy resources providing system security services, and the types of services that may affect network conditions, with a view to determining how the value of distributed energy resources can be maximised for both parties.	
8	The existing frameworks for frequency control may be inadequate to address the future needs of the power system as the demand and supply sides of the sector continue to evolve, but the time frames over which these changes are required, and what new services might be required in future, are uncertain.	That, in the medium term: (a) AEMO conduct a broader review of the MASS to recognise the capability, and more accurately value the response profile, of new technologies that are capable of providing frequency control services (b) the AEMC and AEMO refine the time frames and develop a work program for making any substantive changes to FCAS frameworks, informed by: (i) an assessment of any consequential impacts arising from the implementation of any revisions to frequency control arrangements in the normal operating frequency band (ii) investigations undertaken by AEMO into: — the emerging capabilities of fast frequency response technologies, including trials of various technology types, with a view to publishing the outcomes of the trials with relevant stakeholders, and to inform the development of future service specifications — the evolving technical and operational requirements of the power system and the inter-relationships between different system services, including frequency response, inertia and system strength.	Chapter 8

Contents

1 Introduction

1.1 Purpose of the review

The purpose of the *Frequency control frameworks review* is to explore, and provide advice to the COAG Energy Council and market participants on, any changes required to the market and regulatory frameworks to meet the challenges in maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generation mix in the NEM.[6]

These challenges and opportunities have been raised by a number of organisations, including the Australian Energy Market Operator (AEMO) through its Future Power System Security work program, the Finkel Panel through the *Independent review into the future security of the national electricity market*, and by the AEMC itself through its system security work program.[7] The *Frequency control frameworks review* provides a means by which the AEMC can explore these issues.

Feedback from those involved in the AEMC's system security work program indicated that many stakeholders see value in the AEMC undertaking a comprehensive and holistic review of frequency control arrangements in the NEM to determine whether they remain fit for purpose as the generation mix changes. In their submissions to the issues paper, published in November 2017, a number of stakeholders considered that the review provided a timely opportunity to examine the regulatory and market frameworks that underpin frequency control.[8]

1.2 Scope of the review

The AEMC published terms of reference on 7 July 2017,[9] which noted that the scope of the review may include, but is not limited to, the following:

- assessing whether mandatory governor response requirements should be introduced and investigating any consequential impacts including on the methodology for determining causer pays factors for the recovery of frequency control ancillary service (FCAS) costs
- reviewing the structure of FCAS markets to consider:
    - any drivers for changes to the current arrangements, how to most appropriately incorporate fast frequency response (FFR) services, or

6 The term 'regulatory frameworks' refers to the National Electricity Rules and the National Electricity Law.

7 An overview of the AEMC's system security work program is provided in Figure 2 at the end of the executive summary of this draft report.

8 Submissions to issues paper: AEMO, p. 1; Energy Networks Australia, p. 1; Pacific Hydro, p. 1; TasNetworks, p. 1; Tesla, p. 1.

9 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

alternatively enhancing incentives for FFR services within the current six second contingency service

- — any longer-term options to facilitate co-optimisation between energy, FCAS and inertia provision

- assessing whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day

- considering the potential of distributed energy resources to provide frequency control services and any other specific challenges and opportunities associated with, their participation in system security frameworks.

Items 1 - 3 above are based on recommendations made by the AEMC in the final report of the *System security market frameworks review*. Item 4 is based on a recommendation made by the AEMC in the final report of its *Distribution market model* project.

The issues paper published on this review in November 2017 set out the AEMC's preliminary analysis, and sought stakeholder views on, these issues. In their submissions to the issues paper, stakeholders largely supported the proposed scope of the review, but made a number of suggestions on additional issues to consider. The AEMC's response to these scope issues are set out in Appendix A.

The AEMC has split consideration of the review's terms of reference into two time horizons, as below:

1. **Part A - Immediate priorities**

   — Frequency control during normal operation. The AEMC is exploring the recent deterioration of frequency performance under normal operating conditions, and possible ways in which this could be addressed. It is addressed in Chapter 5 of this draft report.

   — Other improvements to the frequency control frameworks. The AEMC is looking at ways in which the existing forecasting and frequency reporting arrangements could be amended to enhance the operation of the existing frequency control frameworks. It is addressed in Chapter 6 of this draft report.

2. **Part B - Emerging issues**

   — Participation of distributed energy resources in system security frameworks. The AEMC is exploring whether there are any unnecessary regulatory barriers that may prevent distributed energy resources providing FCAS or other system security services. It is addressed in Chapter 7 of this draft report.

— Future FCAS frameworks. The AEMC is looking at the spectrum of approaches to frequency control that could be achieved through market and regulatory arrangements, a longer-term consideration of the appropriateness of the FCAS market arrangements, and ways to facilitate co-optimisation between energy, FCAS and other system characteristics such as inertia. It is addressed in Chapter 8 of this draft report.

The *Frequency control frameworks review* also provides the means to progress a number of the recommendations made by the Finkel Panel in June 2017 in relation to frequency control within the time frames put forward in that review, including:[10]

- moving towards a market-based mechanism for procuring fast frequency response if there is a demonstrated benefit (within three years)
- investigating and deciding on a requirement for all synchronous generators to change their governor settings to provide a more continuous control of frequency within a dead band (by mid-2018)
- reviewing the framework for power system security in respect of distributed energy resources participation (by mid-2019).

The Finkel Panel also recommended that the AEMC require new generators to have fast frequency response capability (by mid-2018). This issue is the subject of a rule change request currently under the AEMC's consideration.[11]

1.3 Related work

This review follows, and is being undertaken alongside, a range of other work being carried out in the system security space by the AEMC, the Reliability Panel and AEMO, including:

- the AEMC's *System security market frameworks review*
- the Reliability Panel's *Review of the frequency operating standard*
- the AEMC's *Reliability frameworks review*
- AEMO's ongoing technical work on frequency control issues
- AEMO's review of the procedure for determining contribution factors for the recovering of regulating FCAS costs
- the Energy Networks Australia / CSIRO *Electricity Network transformation roadmap*

10 See recommendations 2.2, 2.3 and 2.5 of the Finkel Panel's Independent review into the future security of the national electricity market.

11 See: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards

- the commencement of the AEMC's minimum frameworks for inertia and system strength on 1 July 2018.

These projects are summarised in Appendix B and referred to where relevant throughout this draft report.

1.4 Progress to date

The AEMC published an issues paper on the *Frequency control frameworks review* on 7 November 2017. The issues paper:

- provides an overview of frequency control and the drivers for consideration of frequency control arrangements in the NEM
- set out the AEMC's framework for assessing any changes to the existing regulatory or market arrangements for frequency control
- provided the AEMC's preliminary analysis of each of the issues set out in the terms of reference for the review, drawing on the work of other organisations, including AEMO
- sought stakeholder views on the scope and materiality of each of the issues.

Written submissions on the paper closed on 5 December 2017 and are available on the AEMC website.

The AEMC published a progress update on the review for the COAG Energy Council on 19 December 2017. The progress update provided an overview of:

- each of the issues set out in the issues paper
- the AEMC's views on possible options to address the issues
- stakeholder submissions to the issues paper
- the AEMC's proposed next steps for the review.

The issues paper, stakeholder submissions to the issues paper, and the progress update are all available on the AEMC website.[12]

12 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

1.5 Stakeholder consultation

1.5.1 Submissions and comments on this issues paper

The Commission invites written submissions from interested parties in response to this draft report by **24 April 2018**. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

We also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Claire Richards on (02) 8296 7878 or at claire.richards@aemc.gov.au.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0059".

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

If choosing to make submissions by mail, the submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.5.2 Reference group and technical working group

A reference group comprising senior representatives of the AEMC, AEMO, the Australian Energy Regulator (AER) and the Senior Committee of Officials (SCO) has been established to provide high-level input and strategic advice to the AEMC throughout the course of the review.

The AEMC has also established a technical working group to provide technical advice to the AEMC and assist with the development of recommendations for the review. The group comprises representatives from the AER and AEMO, consumer groups, large energy users, conventional generators, renewable energy generators, retailers, energy service providers, and transmission and distribution network service providers.

1.6 Review timeline

The timeline for this review is set out in Table 1.1 below.

Table 1.1 Review timeline

Item	Date
Publication of terms of reference	7 July 2017
Publication of issues paper	7 November 2017
Close of submissions on issues paper	5 December 2017
Publication of progress update to COAG Energy Council	19 December 2017
Publication of draft report	20 March 2018
Close of submissions on draft report	24 April 2018
Publication of final report	July 2018

1.7 Structure of this report

The remainder of this draft report paper is structured as follows:

- Chapter 2 provides an overview of how the existing market and regulatory frameworks are set up to enable frequency control in the NEM.
- Chapter 3 sets out the drivers of change that give the AEMC cause to review the frequency control arrangements in the NEM.
- Chapter 4 sets out the assessment framework for this review.
- Part A sets out the AEMC's analysis and draft recommendations on the immediate priorities for frequency control frameworks, including:
  - frequency control during normal operation (Chapter 5)
  - other improvements to the frequency control frameworks, including forecasting and reporting (Chapter 6)
- Part B sets out the AEMC's analysis and draft recommendations regarding some of the emerging issues for frequency control frameworks, including:
  - the participation of distributed energy resources in system security frameworks (Chapter 7)
  - a longer-term exploration of future FCAS market arrangements (Chapter 8)

2 Overview of frequency control

This section provides an overview of how the existing regulatory framework is set up to enable frequency control, the coordination of FCAS with inertia, and a description of the goals of frequency control during different power system conditions. A short explanation of power system frequency and frequency variation is provided in Appendix C.

2.1 How is the existing regulatory framework set up to enable frequency control?

System security is necessary for the functioning of the power system. Under the National Electricity Law (NEL), AEMO's statutory functions include maintaining and improving power system security.[13]

AEMO is required under the National Electricity Rules (NER) to operate and maintain the power system in a "secure operating state". In order for the electricity system to remain in a secure operating state, there are a number of physical parameters that must be maintained within a defined operating range. An operational power system must also be able to operate satisfactorily under a range of conditions, including in the event of foreseeable contingency events, such as the failure of a single transmission element or generator.

Specifically, AEMO is responsible for maintaining the power system in a secure operating state by satisfying the following two conditions:

1. The system parameters, including frequency, voltage and current flows are within the operational limits of the system elements, referred to as a "satisfactory operating state".

2. The system is able to recover from a credible contingency event or a protected event, in accordance with the power system security standards.[14]

Frequency control is a key element of power system security. To maintain a stable system frequency, AEMO must instantaneously balance the supply of electricity into the power system against consumption of electricity at all times. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.

AEMO manages power system frequency by forecasting the expected load and issuing dispatch instructions to generators to meet that demand. The NER require registered participants to comply with a dispatch instruction given to it by AEMO, unless to do so

13 See section 49(1)(e) of the NEL.

14 Clause 4.2.4(a) of the NER.

would, in the registered participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment.[15]

A number of other components of the regulatory framework are in place to enable AEMO to meet its obligations with respect to frequency control. These are set out below.

2.1.1 Frequency operating standard

The frequency requirements that AEMO must meet are set out in the frequency operating standard, which is defined in the NER and determined by the Reliability Panel. The purpose of the frequency operating standard is to define the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the frequency operating standard, while AEMO is responsible for maintaining the frequency within the ranges defined by the standard. These requirements then inform how AEMO operates the power system, including through applying constraints to the dispatch of generation, or procuring ancillary services.

The frequency operating standard currently consists of two separate standards - one for the mainland NEM and one for Tasmania - to reflect the different physical and market characteristics of the Tasmanian region as opposed to the mainland NEM. The power system frequency is consistent throughout the mainland interconnected transmission network, with frequency centrally controlled during normal operation and the impact and response to frequency disturbances spread throughout the network and the corresponding market participants. Tasmania is connected to the NEM via Basslink, a high voltage DC undersea cable. This cable allows power transfer between the mainland NEM and Tasmania but does not transfer the AC frequency between the two regions. As a result, the Tasmanian power system operates at its own electrical frequency separate from the mainland NEM, but still at a frequency of 50 Hz.

Figure 2.1 and Figure 2.2 set out the frequency bands defined in the frequency operating standard for the mainland NEM and Tasmania.[16]

---

15 Clause 4.9.8(a) of the NER.

16 In accordance with clause 4.3.2(h) of the NER, AEMO is required to undertake an integrated periodic review of power system frequency risks associated with non-credible contingencies in collaboration with network service providers. This review must assess the risks of non-credible contingency events that could involve uncontrolled increases or decreases in frequency leading to cascading outages or major supply disruptions. In September 2017, AEMO published a power system frequency risk review report which recommended the implementation of an under-frequency load shedding scheme in South Australia.

Figure 2.1 Frequency bands - mainland NEM

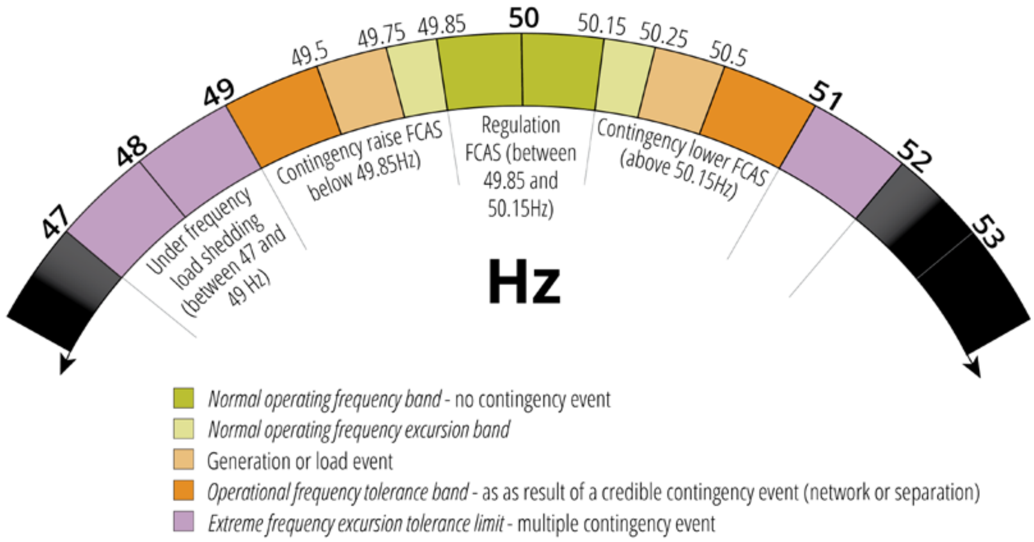
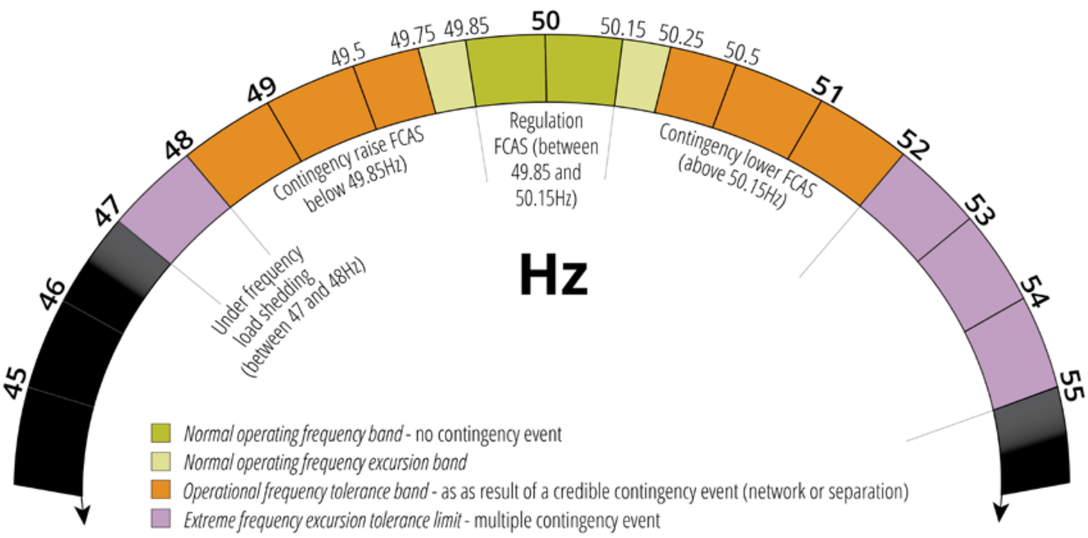


Figure 2.2 Frequency bands - Tasmania



2.1.2 Frequency control ancillary services

Ancillary services under clause 3.11.1 of the NER are services:

> "…that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality."

There are two types of ancillary services provided in the NEM: market and non-market ancillary services. Non-market ancillary services provide (black) system restart and network support (e.g. voltage control) services, and are provided by parties under contract with AEMO.

Market ancillary services are concerned with the timely injection (or reduction) of active power to arrest a change in frequency. AEMO operates the wholesale electricity market, which dispatches electricity generation to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five minute dispatch process which, as explained in Appendix D, can cause frequency variations.

Market ancillary services are procured by AEMO to increase or decrease active power over a timeframe that maintains the technical performance of the power system, in this case, that satisfies the frequency operating standard. AEMO's market ancillary services specification (MASS) defines the technical requirements for the provision of market ancillary services.[17] These services are generally referred to as frequency control ancillary services (FCAS) although this is not a defined term under the NER.

This review is focused on issues surrounding frequency control in the NEM, and therefore focuses on the arrangements for the provision of FCAS.

There are two types of FCAS: regulating and contingency.

Regulating FCAS

The power system frequency is continually fluctuating in response to changing generation and load conditions. To manage this fluctuation, AEMO continuously monitors the power system frequency and sends out "raise" or "lower" signals to registered generators that are dispatched to correct small frequency deviations. The services provided by these generators are called regulating FCAS, as they regulate the power system frequency to keep it within the normal operating frequency band defined in the frequency operating standard.

There are two types of regulating FCAS:

1. Regulating raise service. Used to correct a minor drop in frequency.

2. Regulating lower service. Used to correct a minor rise in frequency.

Collectively, these two services are defined as 'regulation services' in the NER. Note that AEMO often refers to regulating FCAS as 'regulation FCAS'. Regulation services are a form of secondary frequency control, a term discussed in section 2.2.

The operation of regulating FCAS is coordinated by AEMO's automatic generator control (AGC) system. The AGC monitors minor changes in the power system frequency and adjusts the output of regulating FCAS generating units accordingly.

17 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-servicesspecifications-

Contingency FCAS

Under the frequency operating standard, AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. Contingency FCAS is procured by AEMO to respond to larger deviations in power system frequency that are usually the result of contingency events such as the tripping of a large generator or load. Providers of contingency FCAS respond automatically to deviations in the power system frequency outside of the normal operating frequency band.[18]

Contingency FCAS is divided into raise and lower services at three different speeds of response and sustain time: fast (6 seconds), slow (60 seconds) and delayed (5 mins). As such, there are six distinct contingency FCAS services:

1. Fast raise service. 6 second response to arrest a major drop in frequency following a contingency event.

2. Fast lower service. 6 second response to arrest a major rise in frequency following a contingency event.

3. Slow raise service. 60 second response to stabilise frequency following a major drop in frequency.

4. Slow lower service. 60 second response to stabilise frequency following a major rise in frequency.

5. Delayed raise service. 5 minute response to recover frequency to the normal operating band following a major drop in frequency.

6. Delayed lower service. 5 minute response to recover frequency to the normal operating band following a major rise in frequency.[19]

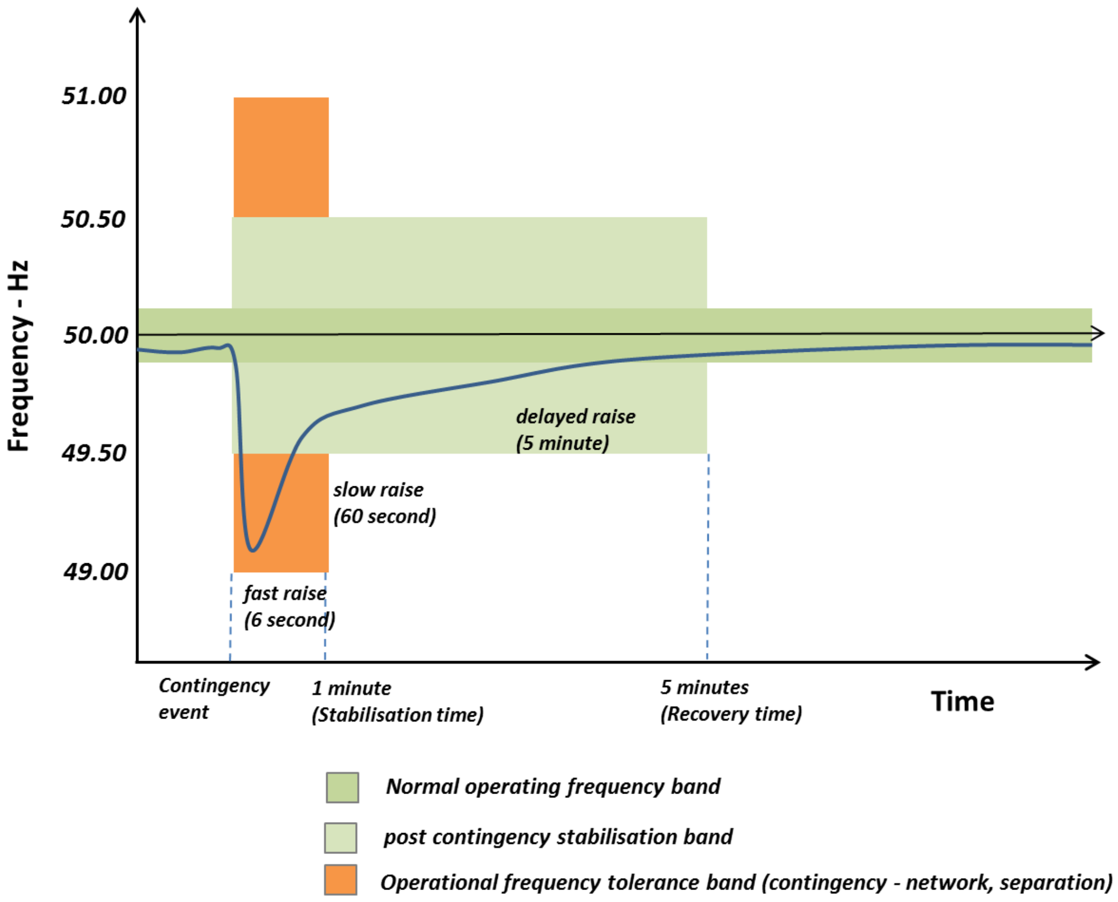
In response to a contingency event, each type of contingency FCAS will work together to recover the power system frequency within the applicable frequency bands and time frames defined in the frequency operating standard, as displayed in Figure 2.3.

---

18 Providers of contingency FCAS respond automatically based on a local measurement of system frequency, in comparison to regulating FCAS which is coordinated by AEMO based on a centralised measurement of system frequency.

19 AEMO, Guide to ancillary services in the national electricity market, April 2015, p. 8.

Figure 2.3 Frequency deviation and FCAS response



The fast and slow contingency services are a form of primary frequency control, a term discussed in section 2.2.

FCAS markets

In the NEM, FCAS is sourced from markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.[20]

There are eight markets in the NEM for FCAS, one for each type of regulating and contingency service. Participants must register with AEMO to participate in each distinct FCAS market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service.

AEMO determines the amount of FCAS that is required to manage the power system frequency in accordance with the frequency operating standard. For each five minute dispatch interval, the national electricity market dispatch engine enables sufficient FCAS in each market, and the price for each service is set by the highest enabled bid in each case.

20 For an introduction to FCAS markets see: AEMO, Guide to ancillary services in the national electricity market, April 2015.

Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour. That is, generators receive a payment irrespective of whether the service is required to be delivered. Where the service is required to be delivered, the generator also receives payment for any energy associated with the provision of the service.

Recovery of regulating FCAS costs

The recovery of AEMO's payments to providers of regulating FCAS is based upon a "causer pays" methodology. Under this framework, market participants are charged according to their contribution to the need for regulating FCAS. A market participant that, through its actions, causes larger deviations in system frequency is charged a proportionately greater amount of money to fund the costs of regulating FCAS.

The NER requires AEMO to create a procedure for determining contribution factors, which reflect the extent to which a market participant caused the need for regulation services. Contributed factors are based on a period of time determined by AEMO, currently a 28-day averaging period.[21] The NER sets out principles to be taken into account in preparing the procedure, and other specific requirements.

AEMO is conducting a review of the causer pays procedure for determining participant contribution factors.[22] The consultation considers potential improvements to the settings and assumptions used in calculating market participant factors under the procedure. The AEMC understands that AEMO is due to publish a draft report and draft procedure shortly.

Recovery of contingency FCAS costs

The recovery of AEMO’s payments to providers of contingency FCAS is based upon a simple categorisation of market participants as either market generators or market customers. The costs of contingency raise services are recovered from market generators, as these services are required to manage the loss of the largest generator on the system. The costs of contingency lower services are recovered from market customers, as these services are required to manage the loss of the largest load or transmission element on the system.

2.1.3 Generator technical performance standards

Equipment that makes up and connects to the power system must perform to certain levels of technical capability. This helps AEMO maintain the power system in a secure and safe operating state and manage the risk of major supply disruptions. The levels of performance for equipment connecting to the power system are set out in performance

---

21 Clause 3.15.6A(k)(4) of the NER.

22 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

standards for each connection. These performance standards are reached through a negotiating framework that is set out in the NER.

'Access standards' in the NER define the range of the technical requirements for the operation of equipment when negotiating a connection. These access standards include a range from the minimum to the automatic access standard. For each technical requirement defined by the access standards, a connection applicant must either:

- meet the automatic access standard, in which case the equipment will not be denied access because of that technical requirement; or
- negotiate a standard of performance with the local network service provider[23] that is at or above the minimum access standard and below the automatic access standard.

The generator access standards in the NER cover a range of technical capabilities for connecting generators, including, among other things, frequency control and response to frequency disturbances during and following contingency events.[24]

Broadly, the automatic access standard that applies to generator frequency control is that:

- the generating system's output should not worsen any frequency deviation
- the generating system must be capable of automatically increasing or decreasing its output to help restore the system frequency to within the normal operating frequency band.[25]

The minimum access standard for generator frequency control does not directly refer to the frequency operating standard. It requires that a generator's output must not:

- increase in response to a rise in system frequency
- decrease more than two per cent per Hz in response to fall in system frequency.[26]

2.1.4 Emergency frequency control schemes

Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. The operational goal of

---

23 The connection applicant may also need to negotiate with AEMO on access standards that are AEMO advisory matters.

24 This section summarises the requirements in the NER that apply to generators connected after the 8 March 2007, when the National Electricity Amendment (Technical Standards for Wind Generation and other Generator Connections) Rule was made. Chapter 11 of the NER contains a transitional rule, clause 11.10.3, that allows for pre-existing access standards to continue to apply.

25 See S5.2.5.11(b) of the NER.

26 See S5.2.5.11(c) of the NER.

emergency frequency control schemes is to act automatically to arrest any severe frequency deviation prior to breaching the extreme frequency excursion tolerance limit, and hence avoid a cascading failure and widespread blackout.

Traditional emergency frequency control schemes operate via frequency sensing relays that detect a frequency deviation beyond a pre-defined set point and act to disconnect any connected generation or load behind the relay. However, schemes can be set up to operate based on the detection of high rates of frequency change from the occurrence of a particular contingency event, such as the failure of an interconnector. The installation and operation of emergency frequency control schemes is the responsibility of the relevant transmission network service provider, while AEMO coordinates the overall performance of the schemes as part of its system security responsibility.

Emergency frequency control schemes were the subject of a rule change request submitted by the South Australian Minister for Energy in July 2016.[27] The AEMC published a final rule determination on this rule change request in March 2017, which sets out a revised framework for the management of emergency frequency control schemes. The AEMC is not aware of any reason to revisit these new arrangements and, as such, emergency frequency control schemes are not considered or discussed in detail in this issues paper.

2.2 Coordinating inertia and frequency control services

Effective control of power system frequency requires the coordination of power system inertia and the provision of a range of frequency control services. These services are intended to work together to maintain a steady power system frequency close to 50 Hz during normal operation, and to react quickly and smoothly to contingency events that cause frequency deviations to stabilise and restore the power system frequency.

As explained above, conventional electricity generators, like hydro, coal and gas, operate with large spinning turbines that are synchronised to the frequency of the grid. Changes to the balance of supply and demand for electricity can act to speed up or slow down the frequency of the system. In each synchronous generating unit, the large rotating mass of the turbine and alternator has a physical inertia which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency. The greater the number of generators synchronised to the system, the higher the system inertia will be and the greater the ability of the system to resist changes in frequency due to sudden changes in supply and demand.

The rate at which the frequency changes following a contingency event, such as the disconnection of a large generating unit, determines the amount of time that is available to arrest the decline or increase in frequency before it moves outside of the permitted operating bands described in the frequency operating standard. The rate of

---

27 See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

change of frequency is proportional to the size of the sudden change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs. The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change. More inertia in the power system means a slower initial decline of power system frequency. However, inertia is not able to stabilise or restore the power system frequency on its own.

When considering frequency control services relevant in the NEM, it is helpful to group them in terms of the immediacy of response they provide to frequency disturbances: primary frequency control or secondary frequency control services.

Primary frequency control services provide the initial response to frequency disturbances. They react automatically and almost instantaneously to locally measured changes in system frequency outside predetermined set points. A primary frequency response is an automatic change in active power generated (or consumed) by a generator (or load) in response to a locally measured change in system frequency.[28]

Historically, primary frequency response band has been provided by the variation of generator output through the generator governor systems that regulate the output of generating units.[29] However, primary frequency response can also be provided by inverter-based generation and loads that are able to vary the active power supplied to or consumed from the power system in response to locally measured changes in frequency.

In the NEM, primary frequency control services that operate outside the normal operating frequency band are procured through the fast and slow contingency FCAS markets. Primary frequency response may also be voluntarily provided by generator governor response and active power control within the normal operating frequency band, but providers are not paid for this service.[30]

Secondary frequency control services refer to those that are intended to restore power system frequency to the nominal frequency (50 Hz).[31]

Under the current market and regulatory arrangements in the NEM, secondary frequency control is provided by:

- generators and loads that are enabled to provide regulating FCAS - these providers vary their generation or load in response to electronic signals sent via AEMO's automatic generation control (AGC) system

---

28 International Council on Large Electric Systems (CIGRE), 2010, Ancillary Services: an overview of International Practices, Working Group C5.06, pp. 7-8.

29 Primary frequency control can be broken down into: continuous primary services that help control power system frequency during normal operation; and primary services that act following larger contingency events. These services are discussed in more detail in Chapter 5.

30 Generator governor response is explained in section 3.1.2 and in Chapter 5.

31 International Council on Large Electric Systems (CIGRE), 2010, Ancillary Services: an overview of International Practices, Working Group C5.06, p. 8.

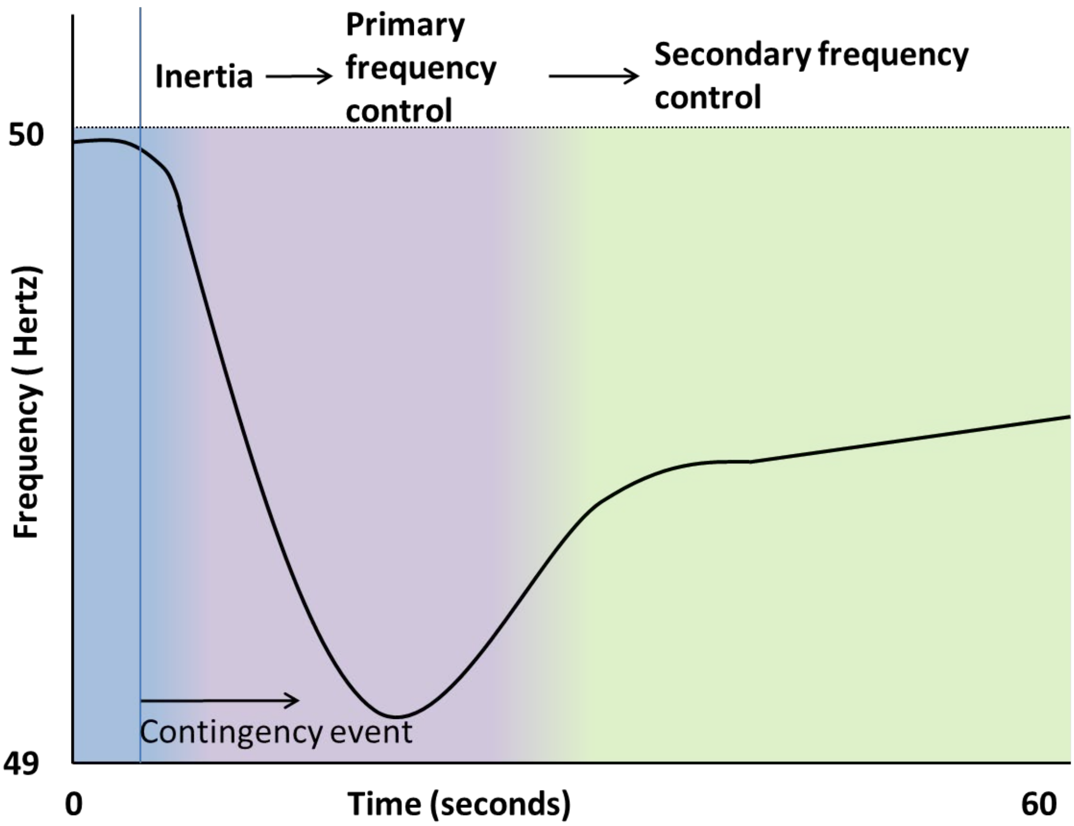
- the delayed contingency service - these providers vary their generation or load in response to a local measurement of frequency or electronic signals sent via the AGC system.

Effective frequency control requires the coordination of inertia and primary and secondary frequency control services.

Beyond the time frames of primary and secondary frequency control, generation capacity is dispatched via the NEM dispatch engine consistent with maintaining a balance between supply and demand.[32]

The interaction of inertia with primary and secondary frequency control is shown below in Figure 2.4.

Figure 2.4 Interaction between inertia, and primary and secondary frequency control



As Figure 2.4 shows, the initial rate of change of system frequency following the contingency event is determined by the system inertia. The lowest point the frequency reaches, called the 'nadir', is determined by the quantity of fast acting primary frequency control that is provided, which acts to stop system frequency falling any further. Primary frequency control is not relied upon to restore the frequency to the nominal frequency of 50Hz. Rather, this is achieved through the provision of secondary frequency control services. A more detailed description of the characteristics

32 Ibid., p. 9.

of primary and secondary frequency control is included in the AEMO advice for this review.[33]

In addition to these services, AEMO is of the view that a *grid formation service* is needed to set the frequency to which the rest of the system is able to be synchronised. AEMO notes that "in large, synchronous power systems like the NEM, frequency has historically been set by synchronous generating units as a by-product of their normal operation" and that "at this time, grid formation is an emerging need rather than a defined service". AEMO's current understanding is that "synchronous generators are the only proven technology that can provide grid forming services in large power systems."[34] The Commission notes that Tesla and S&C Electric Company in their submissions to the issues paper that there are a large number of demonstrated micro-grid projects in the market with inverters operating in grid forming mode that maintain a simulated grid voltage and frequency, which can provide a number of lessons for AEMO.[35]

2.3 Goals of frequency control during different power system conditions

The approach to frequency control in the NEM is best described in terms of three power system conditions:

1. during normal operating conditions
2. during credible contingency events
3. during significant non-credible contingency events.

Each of these is described in more detail below.

2.3.1 Normal operating conditions

Normal operating conditions refer to operation of the power system in the absence of any contingency event, that is, with all generators and network elements operating as expected with no unplanned outages.

There are a number of minor imbalances between supply and demand that may occur during normal operation of the system and which may result in some frequency variation. These kinds of events fall within the scope of normal operation and include:

- errors in the five minute demand forecasts that are used in the dispatch process
- errors in the five minute forecasts of variable intermittent generation, such as wind or solar, that are used in the dispatch process

33 See Appendix D.

34 AEMO, Power system requirements, reference paper, March 2018, pp. 13-15.

35 Submissions on issues paper: S&C Electric Company, p. 9; Tesla, p. 6.

- generating systems not following their dispatch targets
- smaller generating systems or loads partially changing their output or consumption, or tripping altogether.

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

There are two bands within the frequency operating standard that relate to normal operation - the normal operating frequency band and the normal operating frequency excursion band. The intention is that power system frequency should not move beyond these bands in response to the minor events set out above.

2.3.2 Credible contingencies

A secure power system must be able to absorb and recover from significant disturbances that may occur from time to time. These disturbances may be due to the unexpected failure of generation or network elements resulting in a temporary and unexpected imbalance of supply and demand, known as contingency events.

Secure operation in the NEM is defined as a state in which the power system is able to recover from the contingency events that AEMO considers to be reasonably possible in the surrounding circumstances.[36] Such contingency events are known as credible contingency events.[37]

The management of contingency events is prescribed though the frequency operating standard - specifically the settings of the operational frequency tolerance band and a number of narrower bands that set the requirement for certain types of credible contingency events, such as generation, load and network events.

AEMO is required to maintain the power system frequency within these bands when a credible contingency event occurs, and must return the frequency to the normal operating frequency band within a specified time period. Under the existing market arrangements, AEMO procures contingency raise and lower FCAS to manage the consequences of these more significant frequency variations.

2.3.3 Significant non-credible contingency events

The management of the power system during emergency conditions includes the preparation for and operation of the power system in the event of high impact low probability events, such as non-credible contingency events including multiple contingency events and protected events.

---

36 Clause 4.2.4 (a) of the NER.

37 Clause 4.2.3 (b) of NER.

The extreme frequency excursion tolerance limit in the frequency operating standard specifies the limits for satisfactory operation of the power system during emergency conditions. Power system equipment is designed to operate to this range, at least for short periods. Beyond these frequency limits, network equipment and generating systems may be damaged, and therefore, such equipment will include over and under frequency protection systems to remove it from service under very extreme frequency conditions. Emergency frequency control schemes, described in section 2.1.4, aim to maintain the frequency within the extreme frequency excursion tolerance limit.

The power system's ability to withstand or recover from these sorts of significant disruptions is also determined by its 'resilience'. System resilience is supported by:

- high withstand capability of connected equipment - that is, the ability of equipment to continue operation when a significant disruption occurs
- high levels of inertia
- the presence and broad geographical distribution of frequency response services.

System resilience is not an explicit concept set out in the regulatory framework for frequency control. However, it provides a means by which we can consider the benefits of good frequency performance. Improvements in frequency performance during normal operating conditions and during credible contingency events are likely to promote a resilient system.

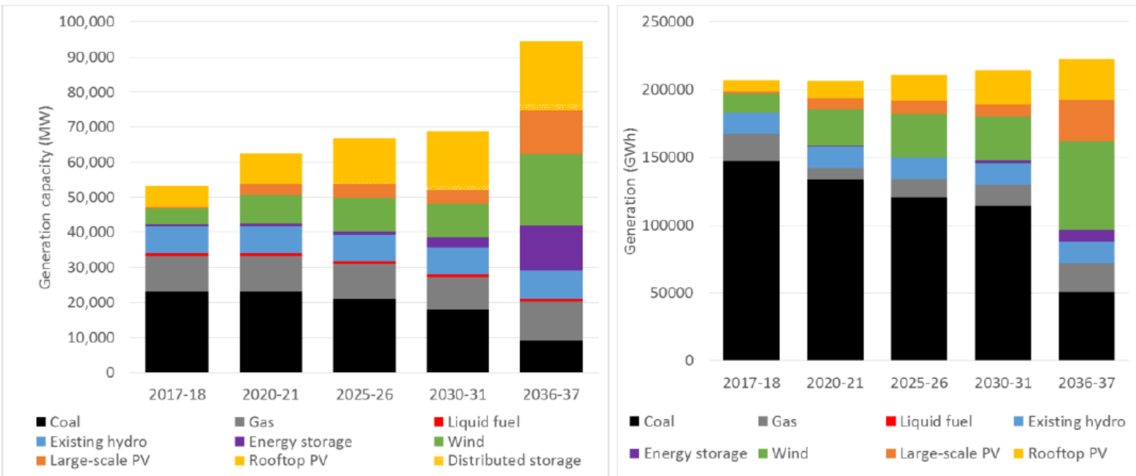
In the AEMC's view, system resilience should be considered separately to good frequency performance, which is defined by shape of the distribution profile of frequency with respect to 50 Hz. The AEMC's views on good frequency performance are set out in Chapter 5.

3 Drivers of change

The electricity industry in Australia is undergoing fundamental change as newer types of electricity generation, such as wind and solar, connect and conventional forms of electricity generation, such as coal, retire. In addition, a formerly passive demand side is becoming increasingly engaged in energy markets through the uptake of new technologies and services, such as solar PV, storage and demand response. These technologies are greatly expanding the choices that consumers have to manage their energy needs. It is also changing the way in which these consumers draw electricity from, and export electricity to, the broader power system.

Figure 3.1 shows AEMO's preliminary projections of NEM generation capacity and output over the next 20 years.[38] These projections show a decline in the amount of coal generation capacity and output, and an increase in the amount of wind and solar capacity and output.

Figure 3.1 Projections of NEM generation capacity (left) and generation output (right)



Source: AEMO, Integrated system plan consultation, December 2017, p. 29.

This transformation has potential implications for the management of power system frequency. Some renewable energy generation technologies are by nature variable. Solar PV panels generate electricity when the sun shines. Wind generators generate electricity when the wind blows. 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.

Specifically, an increased potential for imbalances between electricity demand and supply is driven by:

38 The graphs show AEMO's preliminary projections of the NEM generation mix transformation, modelled under neutral scenario assumptions.

- a reduction in frequency control capability
- increased variability and unpredictability of supply and demand.

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

Further, the existing frequency control frameworks were largely established when the technical characteristics and capabilities of the generation mix were very different. As the generation fleet changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve. There may now be opportunities for the new energy technologies being connected to provide services that help support power system security, including frequency control.

These challenges and opportunities call into question the need for changes to frequency control frameworks to make sure they remain suitable and sufficiently flexible so as not to preclude the participation of emerging technologies. Over time, there is likely to be a need to re-evaluate these frameworks to make sure they remain appropriate and effective in light of any new or emerging drivers of change.

This chapter explores the two drivers of change set out above, which the AEMC considers give rise to a need to review the frequency control frameworks to determine whether they will remain fit for purpose as the generation mix changes.

3.1 Reduction in frequency control capability

3.1.1 Exit of traditional providers of inertia and FCAS

Historically, most generation in the NEM has been synchronous. The gradual withdrawal of synchronous generation is contributing to a reduction in the availability of inertia and traditional providers of ancillary services such as FCAS.

Inertia is naturally provided by conventional electricity generation technologies, such as hydro, coal-fired and gas-fired power stations, that operate with large spinning turbines and alternators that are synchronised to the frequency of the grid. These generators have significant physical inertia and support the stability of the power system by working together to resist frequency disturbances in the power system. Inertia determines how fast frequency changes immediately following a contingency event. This is called the initial rate of change of frequency (RoCoF).

Newer electricity generation technologies, such as wind and solar PV, are connected to the power system via electrical inverters and are not synchronised to the grid. International experience suggests that it is currently not possible to operate a large power system without some synchronous inertia, and that "synthetic" inertia from non-synchronous generators does not provide a direct replacement.[39]

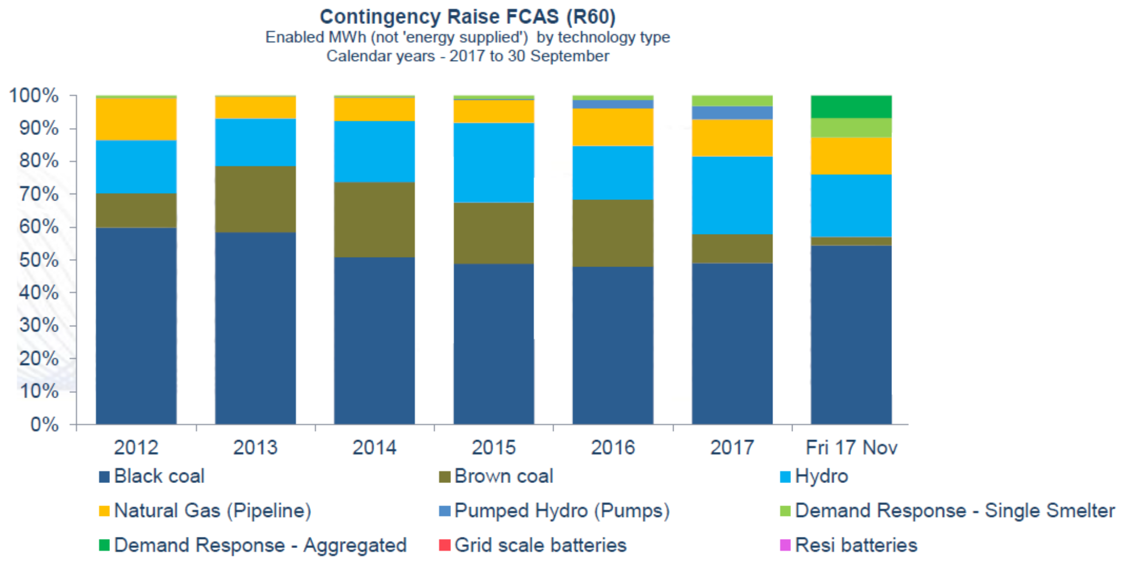
39 The AEMC notes a study undertaken by Everoze drawing on research by Queen’s University Belfast that suggests battery technology has the ability to provide an effective synthetic inertial

As most generation in the NEM has historically been synchronous, the inertia they provide has not been separately valued. As the generation mix shifts to include smaller and more non-synchronous generation, inertia is not provided as a matter of course. This is making it increasingly challenging for AEMO to maintain the power system in a secure operating state.[40]

In its submission to the issues paper, EnergyAustralia noted that the recent rule change mandating minimum levels of inertia was likely to impact frequency control requirements, as inertia reduces the requirement for faster frequency response.[41]

The market has historically attracted regulation and contingency FCAS from synchronous generation. The withdrawal of synchronous generation therefore also contributes to a reduction in the availability of these services in the NEM. If this synchronous generation is displaced (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources. Figure 3.2 shows that the supply mix for the slow contingency raise service is changing as more non-synchronous generators are enabled in that market.

Figure 3.2 The changing supply mix for FCAS



Sources: AEMO, EnerNOC

Additionally, the increasing variability of supply and demand as a result of the connection of non-dispatchable capacity is likely to require increased frequency control from the market.

---

response by providing a very rapid response to frequency variations. See: http://s2.q4cdn.com/601666628/files/doc_presentations/2017/Everoze-Batteries-Beyond-the-Spin.pdf

40 Recent declining levels of inertia is also the subject of the *Managing the rate of change of power system frequency* and *Inertia ancillary service market* rule change requests. See the AEMC website for further information about these rule changes.

41 EnergyAustralia, submission on issues paper, p. 4.

AEMO may use other means to maintain the secure operation of the power system in the event that insufficient FCAS is available to manage the risk of a credible contingency event. Alternative means include the pre-emptive constraining of interconnector flows or generation output to reduce the size of the possible contingency event, and/or to require additional reserve capacity to be available to respond to a contingency event. As the size of system disturbances increases and as the amount of inertia decreases, the amount and speed of FCAS response needed to keep system frequency within the frequency operating standard (and avoid load or generator shedding) increases.

There are a range of new technologies connecting to the system, including battery storage, that are capable of providing FCAS. The types of providers of FCAS in future are therefore likely to change as the generation mix changes. Further, these technologies offer the potential to provide frequency response services that act much faster than the existing services, perhaps as quickly as a few hundred milliseconds. Such fast frequency response (FFR) services would act to arrest the frequency change more quickly than the fastest existing contingency service, which has a response time of up to six seconds. Although FFR services could be procured through the existing six second contingency service, this does not necessarily recognise any enhanced value that might be associated with the faster response. Possible solutions to this issue are set out in Chapter 8.

3.1.2 Reduction in frequency response during normal operation

Generator frequency response

Frequency performance under normal operating conditions has been deteriorating in recent times – that is, there has been a flattening of the distribution of frequency within the normal operating frequency band. As a result, the power system frequency in both the mainland and in Tasmania increasingly operates further away from the nominal frequency of 50 Hz than has historically been the case. AEMO has also noted an increased incidence of exceedance events, where the power system frequency falls outside the normal operating frequency band.

Analysis undertaken for AEMO by consultants, DIgSILENT, indicates that this deterioration has largely been caused by generators decreasing or removing their responsiveness to frequency deviations within the normal operating frequency band. It shows that there has been a very significant decline in the amount of governor response being provided within the normal operating frequency band. DIgSILENT concluded that this has had an adverse impact on the performance of frequency regulation within the normal operating frequency band.[42]

AEMO is concerned that there are risks and costs associated with the power system operating more often at frequencies at the edges of the normal operating frequency

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

band. Some of the consequences of deteriorating frequency control performance include an increase in regulating FCAS costs and a reduction in system resilience to contingency events.

More detailed evidence and analysis of this issue, including the consequences of deteriorating frequency control performance, possible causes of the deterioration and the AEMC's proposed solutions are set out in Chapter 5. Stakeholders provided a range of views on the materiality and drivers of this degradation in their submissions to the issues paper. These submissions are set out and addressed in Chapter 5 as well.

Load frequency response

Load frequency response refers to the natural reduction of power demand from some loads due to a reduction in power system frequency. This effect helps moderate the impact of any frequency deviation by lessening the supply/demand imbalance that causes the frequency change.

Load frequency response is typically provided by direct-connected induction motors. Inverter-connected motors and pumps do not necessarily provide this load frequency response.[43] The DIgSILENT analysis identified a reduction in load frequency response as a contributing factor to the decline of frequency control performance in the NEM under normal operating conditions.[44] This reduction in load frequency response is attributed to a trend of older, direct-connected equipment being replaced with newer, inverter-connected equipment. Examples of this include:

- the use of variable speed drives for motors in industrial loads
- the increase of inverter-based residential appliances such air conditioners.

DIgSILENT's investigations indicate that the impact of this change may be slight at present but is expected to grow over time.[45]

43 As with inverter-connected generators such as wind turbines and solar PV, inverter-connected loads are connected to the power system through power electronic equipment that separates the electrical frequency of the device for that of the power system. As a result, such equipment does not naturally respond to changes in power system frequency as a direct-connected machine would do. It is possible to program inverter-connected machines to provide a frequency response, but this is not currently a default setting.

44 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 26.

45 Ibid.

3.2 Increased variability and unpredictability of supply and demand

3.2.1 Increasingly rapid changes in supply and demand

As set out above, some renewable energy generation technologies are by nature variable. Solar PV panels generate electricity when the sun shines. Wind generators generate electricity when the wind blows.

Some aspects of that variability are relatively predictable. For example, the output of solar PV panels will vary as the sun rises and sets. Other factors leading to variability can be relatively unpredictable. For example, clouds covering a solar PV panel, or wind suddenly dropping, can potentially result in more rapid changes in power output. The predictability of changes in power output varies over time as well. For example, solar PV output can be considered to be relatively predictable on an average basis several months in advance. It is even possible to use weather technology to predict when clouds are moving across the sky, however, the exact timing of when a cloud moves across a particular panel may be difficult to predict.

Predictability of changes in power output has also been affected by technological developments, market and regulatory developments and innovation by demand-side management providers over the past decade. These developments have made it easier for consumers across all sectors (industrial, commercial and residential) to adapt their consumption patterns to manage and control their energy use, and, in turn, their expenditure. For example, home energy management systems can provide demand response and deliver load reductions in a way that goes largely unnoticed by the customer. However, these developments have implications for the management of the power system.

Load (or demand) forecasting has typically relied on the underlying diversity in consumer behaviour. Generally, not all appliances are used at the same time or in the same ways. However, the operation of distributed energy resources (e.g. home management systems or batteries) may be less predictable for AEMO and network service providers, particularly if they are driven by proprietary algorithms. Over time, the operation of this capacity may have increasing implications for the supply and demand balance of the NEM within five minute dispatch intervals, and therefore impact frequency control frameworks.

AEMO does not currently forecast changes in demand due to the operation of distributed energy resources for the purposes of dispatch or pre-dispatch in the NEM, as it is currently a relatively small factor influencing demand on the NEM. However, it is expected to grow. Similarly, virtual power plants (comprising many distributed energy resources) that fall below AEMO's threshold for scheduled or semi-scheduled generators (currently 30MW) are not centrally dispatched by AEMO. Distributed energy resources are also not subject to the technical parameters in the NER that registered participants are, such as performance standards. As a result, AEMO has no direct levers to control the operation of these systems to maintain power system security (unless they are over 30MW). This may increasingly become a challenge for

AEMO as more and more distributed energy resources are aggregated under commercial arrangements to charge and discharge without AEMO's knowledge or control.

AEMO, through its Future Power System Security program, is considering new ways to forecast and manage the way that consumers with new energy technologies use the grid so that it can maintain power system security. The AEMC has therefore excluded further consideration of this issue from the scope of the *Frequency control frameworks review*. Solutions to broader regulatory issues associated with virtual power plants, such as the threshold capacity at which they might need to participate in AEMO's central dispatch process, are not within the scope of this review and are therefore not considered further. Nevertheless, the AEMC recognises that it is an important issue that will likely need to be addressed at some stage.

The concept of predictability is also important for larger generators and loads because it impacts the way that AEMO dispatches energy in the NEM to balance supply and demand, which has important implications for the frequency of the power system.

Generators in the NEM must be classified as either scheduled, semi-scheduled, or non-scheduled generators. Generally, a large generator (30 MW and over) that is capable of participating in the central dispatch process is classified as a scheduled generator, a large generator that has intermittent output (such as a wind or solar farm) is classified as a semi-scheduled generator, and a smaller generator (less than 30 MW) or a generator that is not capable of participating in AEMO's central dispatch process, is classified as a non-scheduled generator.[46]

Scheduled and semi-scheduled generators participate in AEMO's central dispatch process. In this process AEMO receives bids from scheduled and semi-scheduled generators and prepares a forecast of the demand and supply of all participants who are not scheduled (that is, semi-scheduled and non-scheduled generators). The forecast of demand currently includes forecasts of rooftop solar PV production, but not how aggregated home energy management systems or batteries will behave. An overview of the central dispatch process, including forecasting of variable supply (non-scheduled and semi-scheduled generation) and variable load (rooftop solar PV) is provided in AEMO's *Visibility of distributed energy resources* report.[47]

AEMO dispatches capacity in the market every five-minutes to balance supply and demand in the NEM in real-time. Generators specify in their bids their ability to ramp up or down to meet new targets set by AEMO. AEMO's dispatch instructions to scheduled generators take into account the 'ramp rates' they are able to achieve. AEMO can limit a semi-scheduled generator’s output in response to network constraints or because it is out of merit in the dispatch process, but at other times the generator can supply up to its maximum registered capacity.

46 See clauses 2.2.2, 2.2.7(a) and 2.2.3 of the NER.

47 AEMO, Visibility of distributed energy resources, January 2017, p. 27.

With changes in output from semi-scheduled and non-scheduled generators or behind the meter rooftop solar PV, as well as changes in demand due to the operation of home energy management systems or batteries (together 'non-dispatchable capacity'), scheduled generation sources are required to "ramp up" or "ramp down" so that supply matches demand in real time. This gives rise to two issues:

- an increased need for ramping to meet rapid aggregate changes in output from non-dispatchable capacity as the sun rises and sets
- an increased need for ramping to respond to sudden changes in output from non-dispatchable sources of supply due to changing weather conditions, and flexible demand due to changes in their operation - referred to in this chapter as 'rapid ramping requirements'.

The AEMC is considering the first issue through the *Reliability frameworks review*.[48] Specifically, that review is exploring the concepts of dispatchability and flexibility, and AEMO's forecasting arrangements to determine whether changes to the market or regulatory frameworks are required to maintain reliability in the NEM. A directions paper on that review is due to be published on 27 March 2018. As such, this draft report does not further consider the issue any further.

The more relevant aspects of ramping for the purposes of this review are the changes in non-dispatchable capacity on shorter time scales, within the five minute dispatch interval. These more rapid changes could influence the need for capacity to manage frequency through FCAS or other frequency control frameworks. These issues are discussed in the next section.

Rapid ramping requirements

To balance supply and demand, AEMO dispatches scheduled generation to meet its forecast demand. In forecasting demand, AEMO takes into account the expected generation from semi-scheduled, non-scheduled and rooftop solar PV generation. Forecasting the levels of scheduled generation to dispatch may become more difficult with higher proportions of non-dispatchable capacity and flexible demand (that is, home energy management systems and batteries) in the market. This could potentially increase the overall levels of uncertainty in the five-minute dispatch process, which may influence requirements for services to maintain frequency within the frequency operating standard.

In its *South Australian wind study* report, AEMO analysed the changes in total output of wind generation in South Australia over five minute periods and considered the variations in total demand and residual demand (demand less wind generation) over five minute periods. In the report, AEMO noted that variations in output from individual wind farms may be offset by nearby wind farms. It also observed this ‘smoothing’ effect across all of South Australian wind generation. AEMO concluded that when aggregated across South Australia the variability of wind farms reduces

48 See: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

when compared with individual areas, indicating that greater geographical diversity in wind generation leads to lower absolute variability.[49]

Similar analysis has not been conducted for large scale solar PV, but it is reasonable to expect that the smoothing effect of geographical diversity would also apply. It is also reasonable to expect that diversity in technology type would have a similar smoothing effect.

Geographical diversity may therefore lessen the overall variability of wind and solar capacity from what was expected during a five minute dispatch interval. Regardless, it appears that overall an increased amount of variable generation can result in some cases of relatively high variations in output that could potentially create imbalances in supply and demand, and so affect frequency.

These variations will not trigger a need for frequency measures (such as regulating FCAS) to be used, unless the variations were not expected and insufficient generation was dispatched to meet demand. That is, it is the variation in actual output or load from the forecast output or load within the five minute dispatch interval that creates the imbalance and subsequent impact on frequency.

AEMO is required to prepare forecasts of the available capacity of each semi-scheduled generating unit for the purposes of projected assessment of system adequacy, dispatch and pre-dispatch.[50] AEMO has developed a wind energy forecasting system that forecasts large scale wind generation, AWEFS, and a solar energy forecasting system that forecasts large scale and rooftop solar PV generation, ASEFS.[51] A detailed explanation of AWEFS and ASEFS is provided in the AEMC's *Reliability frameworks review* issues paper.[52]

The Reliability Panel's 2016 *Annual market performance review* assessed the accuracy of AEMO's forecasting of wind generation. The results show an average variance of at or less than one per cent of forecast five minute output from actual output for each month in the period 2015-16. Figure 3.3 shows the normalised mean variances for a range of time horizons from five minutes to six days ahead.

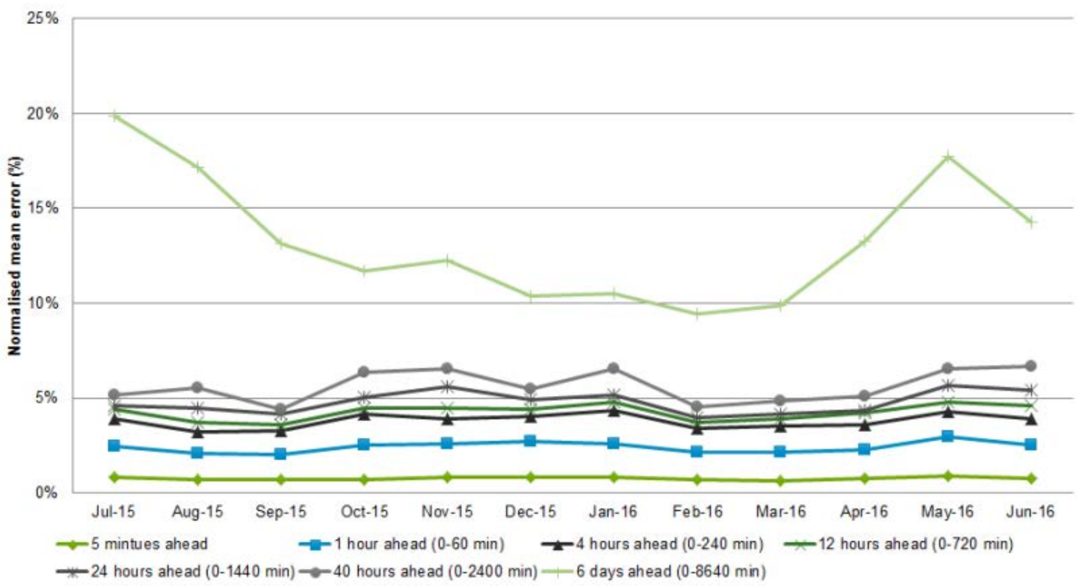
49 Ibid, p. 28.

50 See clause 3.7B of the NER.

51 AWEFS was implemented in two stages between 2008 and 2010 and ASEFS was implemented in two stages in 2014 and 2016.

52 AEMC, Reliability frameworks review: issues paper, August 2017, p. 46.

Figure 3.3 NEM-wide variations between forecast and actual wind output



When taken together, the analysis above shows that at times there will be variations in the output of variable generation between one five minute dispatch interval and the next. It also shows that AEMO forecasts these variations for, among other purposes, determining its dispatch instructions to scheduled generators to meet demand. A mismatch in supply and demand leading to an impact on the frequency of the power system should only occur where there is a difference between the forecast variation in the output of non-dispatchable capacity over the five minute dispatch interval, and the actual output of that capacity across the same period. As noted above, the NEM-wide average variation between forecast and actual wind generation is relatively low at or below one per cent. As a result, even if wind generation falls by 100 MW across a region, the difference between actual and forecast generation may on average be as little as 1 MW.

These effects may be more significant by region or sub-region when taking into account the reverse effect of smoothing across the NEM. They may also be less significant taking into account smoothing across different technology types (solar and wind) within the region. However, there is no published data available on the variation between forecast and actual large-scale solar generation or rooftop solar PV within five minute intervals in the NEM.

The AEMC sought views on the materiality of the frequency impacts of variable generation and flexible demand within five minute dispatch intervals.

The Clean Energy Council noted that it may be necessary to consider alternative market mechanisms beyond FCAS that can deliver ramping services into the NEM. It suggested that this could include day-ahead market arrangements that contract for specific ramping capabilities to be available and triggered when needed.[53]

53 Clean Energy Council, submission on issues paper, p. 4.

If a mismatch between the expected and actual output from variable generation or load from flexible demand occurs within the five minute dispatch interval, the existing mechanisms to control frequency on the power system are expected to address the mismatch. However, as is set out in Chapters 6 and 8, there may be ways in which these arrangements could be improved.

Several stakeholders considered that better forecasting arrangements would help to address the frequency impacts of variability in variable generation. These views are set out and addressed in Chapter 6.

3.2.2 Lack of visibility of the operation of distributed energy resources

The increased uptake of new technologies on the demand side is greatly expanding the choices that consumers have to manage their energy needs. It is also changing the way in which these consumers draw electricity from, and export electricity to, the broader power system.

These changes are presenting challenges for AEMO in managing power system security. Distributed energy resources are not centrally dispatched by AEMO and are not subject to the technical parameters in the NER that registered participants are, such as performance standards. As a result, AEMO has no direct levers to control the operation of these systems to maintain power system security.

Similarly, AEMO does not currently forecast changes in demand due to the operation of home energy management systems or batteries for the purposes of dispatch or pre-dispatch in the NEM as it is currently a relatively small factor influencing demand on the NEM. However, it is expected to grow. Over time, the operation of this capacity may have increasing implications for the supply and demand balance of the NEM within five minute dispatch intervals, and therefore impact frequency control frameworks.

AEMO, through its Future Power System Security program, is considering new ways to forecast and manage the way that consumers with new energy technologies use the grid so that it can maintain power system security. Specifically, it is exploring ways to improve its visibility of distributed energy resources. AEMO's demand-side participation guidelines will require registered participants to submit demand-side participation data annually at the national metering identifier level from April 2018. AEMO is also undertaking a range of work in the context of distributed energy resources and power system security, including its visibility of distributed energy resources project.[54]

Given the range of work AEMO is undertaking in this space, the AEMC has excluded further consideration of this issue from the scope of the *Frequency control frameworks review*.

---

54 See: AEMO, Visibility of distributed energy resources, January 2017.

4 Assessment framework

This chapter sets out the AEMC's assessment framework for undertaking the *Frequency control frameworks review*.

4.1 The national electricity objective

The overarching objective guiding the Commission's approach to this review is the national electricity objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. The NEO is set out in section 7 of the NEL, which states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The Commission considers that the relevant aspects of the NEO for this review are the efficient investment in, and operation of electricity with respect to the price and security of supply of electricity, as well as the safety and security of the national electricity system.

4.2 Trade-offs inherent in frequency control frameworks

Consistent with the relevant aspects of the NEO identified above, there is a requirement to consider that the achievement of higher levels of system security, through enhanced frequency control, is likely to entail a cost trade-off. It is possible that enhanced frequency control, delivered through a greater volume of ancillary services or stricter requirements on market participants, will involve an additional cost, which may increase the price of electricity to consumers. It is equally possible that optimising the design and implementation of FCAS markets may enable the delivery of enhanced frequency control at no additional cost or even with a cost reduction.

The key question for this review is therefore how to create frequency control (and associated services) frameworks that minimise the costs of achieving the frequency operating standard (consistent with the desired level of system security), given the emerging changes in the NEM and associated uncertainties.

Broadly, delivery options can be thought of as reflecting greater or lesser reliance on two principal approaches, namely:

- market-based mechanisms

- intervention and regulatory mechanisms.

The existing frequency control framework, as set out in section 2.1, is largely market-based, but does have some elements of intervention intrinsic in its design, such as generator technical performance standards and associated governor or inverter settings.

The Commission considers that intervention-based approaches, however well designed, are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets are generally the most efficient mechanism to further the interests of consumers through allowing efficient price discovery and production decisions based on competitive market dynamics, even where consumers do not directly participate (as is true for energy-related markets such as the NEM and FCAS markets).

By allocating risks to market participants, markets provide financial incentives to make efficient decisions and provide incentives for innovation, to the benefit of consumers.

Intervention-based approaches, on the other hand, tend to provide higher levels of certainty of a secure supply of energy. Such approaches are sometimes preferred when dealing with issues of system security because they tend to provide a higher level of confidence that the system can be maintained in a secure operating state for a wide range of conditions and circumstances.

Therefore, there are different costs and benefits for market-based or intervention-based approaches. Centralised control over security provides a high degree of certainty that a secure supply of electricity will be achieved. However, such an approach will likely foreclose the considerable potential benefits of a well-functioning market, imposing costs and risks on consumers. But, in some instances (for example, where security concerns are manifesting in operational time scales or where the risk external to the energy market prevents it from being well-functioning), intervention mechanisms are likely to be appropriate in order to maintain the integrity of the power system.

4.3 Principles

The Commission has developed a set of principles to guide the development of recommendations on potential changes to the market and regulatory frameworks that affect security in the NEM in light of the trade-offs set out above.

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a secure supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by consumers. Solutions that are better able to allocate risks to market participants such as businesses who are better able to manage them are preferred where practicable.

2. **Efficient investment in, and operation of, energy resources to promote a secure supply:** Any frequency control framework should result in efficient investment in, and operation of, energy resources to promote a secure supply of electricity for consumers. However, there are costs associated with provision of energy resources, which should be assessed against the role that a secure power system plays in delivering reliability to consumers. Frequency control frameworks should also seek to minimise distortions in order to promote the effective functioning of the market.

3. **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.

4. **Flexible:** 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. 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 it is needed, while not imposing undue market or compliance costs on other areas.

5. **Transparent, predictable and simple:** Frequency control frameworks should promote transparency as well as being predictable, so that market participants are informed about aspects that affect security, and so can make efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

The issues paper set out these principles and sought stakeholder views on them. Several stakeholders expressed support for the principles,[55] and others suggested that the AEMC have consideration of a number of others. These suggested principles, and the Commission's response, are set out in Table 4.1.

Table 4.1 Stakeholders' proposed principles

Proposed principle	AEMC response
All connecting parties should be treated fairly and equitably.[56]	This concept is inherent in principle 1: appropriate risk allocation.

55 Submissions to issues paper: Energy Queensland, p. 6; Hydro Tasmania, p. 6; Snowy Hydro, p. 6.

56 S&C Electric Company, submission to issues paper, p. 5.

Proposed principle	AEMC response
Any changes to the existing frequency control framework must ensure that existing generation does not suffer additional costs that were not anticipated at the time of commissioning of the plant, or forced to retire prematurely by the imposition of a mandatory framework that physically cannot be met.[57]	This concept is inherent in principle 1: appropriate risk allocation and principle 3: technology neutral.
Market-based approaches are preferable to mandated services,[58] but regulatory interventions may still be needed, for example where there are technical constraints or specific network requirements.[59]	The AEMC supports this view, as set in section xx. However, the AEMC considers that this is a philosophy that underpins the AEMC's approach to the review, rather than a principle in itself. The principles provide a means by which the AEMC can determine whether a market-based approach or a regulatory-based approach better addresses the identified issue.
Technology neutrality is important, but should recognise that all technologies have their own technical characteristics that must work within the limits of their control boundaries.[60]	This concept is inherent in principle 3: technology neutral.
Efficient frequency control is provided when all units act to support the power system.[61]	The AEMC is of the view that this is not a principle, but rather a view that is open to challenge. The question of whether 'good frequency control' is achieved when all units are providing frequency response is addressed in Chapter 5.
Ensure regulatory and commercial outcomes are aligned with good engineering practice.[62]	The AEMC supports this view. While market and regulatory frameworks should be designed to maximise efficient outcomes, the Commission considers that this should not come at the expense of a safe and secure power system.

Noting that several overlap with those set out by the AEMC in the issues paper, AEMO's submission sets out some assessment principles for the review.[63] These principles, and the Commission's response, are set out in Table 4.2.

57 Snowy Hydro, submission to issues paper, p. 6.

58 Australian Energy Council, submission to issues paper, p. 2.

59 Tesla, submission to issues paper, p. 3.

60 Pacific Hydro, submission to issues paper, p. 7.

61 Ibid.

62 Hydro Tasmania, submission to issues paper, p. 6.

63 AEMO, submission to issues paper, pp. 10-11.

Table 4.2 AEMO's proposed principles

Proposed principle	AEMC response
Frequency control requirements should be defined in terms of the fundamental power system needs.	The AEMC does not consider this to be a principle against which possible solutions to identified issues should be assessed. Rather, it is a view on how the AEMC should identify the issues and possible solutions.
Target flexibility and adaptability.	This concept is inherent in principle 4: flexible.
Ensure services are predictable, verifiable and assessable.	Noted. The AEMC proposes to include this in principle 5: transparent, predictable and simple.
Adopt a performance-based approach to procurement and payment.	This concept is inherent in principle 1: appropriate risk allocation.
Be willing to implement solutions in the short and medium term while progressing longer-term solutions.	The AEMC does not consider this to be a principle against which possible solutions to identified issues should be assessed. Rather, it is a view on how the AEMC should stage these solutions. The AEMC's consideration of the implementation of the various recommendations in this draft report are set out in the relevant chapters.
Consider all options.	The AEMC does not consider this to be a principle against which possible solutions to identified issues should be assessed. Rather, it is a view on how the AEMC should identify the issues and possible solutions. The possible solutions identified in this draft report cover all known viable options. And, as set out in principle 3: technology neutral, the AEMC is of the view that regulatory arrangements should be designed to take into account the full range of potential market and network solutions.
Inclusiveness and ease of entry/exit.	This concept is inherent in principle 3: technology neutrality, principle 4: flexible and principle 5: transparent, predictable and simple.
Ensure energy delivery is not systematically prioritised over system service delivery.	This concept is inherent in principle 2: efficient investment in, and operation of, energy resources to promote a secure supply.

4.4 Assessment approach

The Commission has adopted the following approach to assessing frequency control markets and regulatory arrangements, and developing recommendations as part of this review:

1. Define the issues

The first step in the assessment framework is to define the problem or issues that have been identified in relation to frequency control frameworks in the NEM. Chapters 5 through 8 of this report set out the AEMC's views on the specific issues that it considers need to be addressed, informed by AEMO analysis and stakeholder input.

2. Determine the options available

The purpose of the review is to identify any changes to market and regulatory frameworks that will be required to address the issues identified through the above process. The review is considering both modifications to existing market and regulatory arrangements, as well as potentially new arrangements to address the identified issues. It is also considering how these elements could address security in both the short- and long-term.

These options will identify potential changes to the existing frequency control frameworks that could better allow for efficient provision of frequency control, ultimately resulting in a secure electricity supply.

3. Assess the range of options against the NEO and guiding principles

Any recommendations for potential changes to market and regulatory frameworks developed by the Commission need to result in net benefits to the market and promote the long-term interests of consumers, consistent with the NEO. The Commission's assessment of the options, and the development of recommendations in this review, has been guided by the framework principles set out above.

In their submissions to the issues paper, several stakeholders expressed support for this assessment approach.[64]

Tesla considered that such an approach works best for dealing with non-structural regulatory changes, or introducing new technologies that have long project development lead times. It suggested that the AEMC instead consider a 'regulatory sandboxing' approach to provide empirical evidence of how some of the new services should operate in the market, and whether they are suitable for the needs of the system. Tesla was of the view that such an assessment approach would be an important step in fundamentally redesigning the NEM to adapt to non-synchronous generation technologies.[65] As set out in principle 3 above, the AEMC's objective is to

---

64 Submissions to issues paper: Energy Queensland, p. 6; Hydro Tasmania, p. 6; Snowy Hydro, p. 6.

65 Tesla, submission to issues paper, pp. 3-4.

put in place a regulatory framework that enables the delivery of services that are needed to support power system security. The AEMC is of the view that testing of the capabilities of particular technologies to determine whether they are suitable for the needs of the power system is, while likely to be valuable, a function best carried out by other organisations, such as AEMO or ARENA.

4.5 Time frames for making changes to frequency control frameworks

Since establishment in 2001, the existing frameworks for procuring frequency control services have proved effective in optimising the dispatch of FCAS sources in real time to provide efficient market outcomes. However, recent and potential future changes to the types of technologies used to control system frequency are challenging the efficiency of these market outcomes, with potential implications for system security.

The gradual shift towards more non-synchronous and 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, and limits the potential to control these frequency disturbances.

The Commission considers that, as this shift in generation technology continues, there is likely to be a growing need to re-evaluate the current design of frameworks for frequency control services. New approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies.

However, changes to these frameworks are likely to involve their own set of costs, both in terms of implementation but also in the means by which frequency control services are procured. Furthermore, some technologies that provide frequency control services also have the potential to provide other system supporting services, such as system strength, and so frameworks designed for frequency control must also consider the implications for these services.

While there is some evidence that the current frameworks are already limiting the efficiency of market outcomes, moving immediately to a completely new set of arrangements for the procurement of frequency control services also may not be appropriate in the current market environment.

The Commission has therefore divided its assessment of proposed changes to frequency control frameworks into two categories. These categories are based on the Commission's prioritisation of the need for changes to be determined and implemented over time.

Part A: Immediate priorities

Frequency performance under normal operation has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band. The Commission has proposed a number of changes to the existing frequency control frameworks to address this deterioration in frequency performance, including the creation of incentives for the provision of a primary regulating response, improvements in the transparency and simplicity of cost recovery arrangements, and increased monitoring and reporting of frequency performance. The Commission's discussion of these proposals is set out in chapters 5 and 6 of this draft report.

Part B: Emerging issues

An increased potential for imbalances between electricity demand and supply is being driven over time by a reduction in frequency control capability and increased variability and unpredictability of generating technologies and consumer behaviour. As the generation fleet changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve. These challenges and opportunities call into question the need for changes to frequency control frameworks to make sure they remain suitable and sufficiently flexible so as not to preclude the participation of emerging technologies, such as distributed energy resources, and to allow for the effective coordination with other services necessary to support the security of the power system. The Commission's discussion of changes to frequency control frameworks to facilitate these emerging issues is set out in chapters 7 and 8 of this draft report.

5 Frequency regulation during normal operation

This section describes the issues that have been identified that relate to frequency control during normal operation.

- Section 5.1 provides an overview of the recent degradation of frequency performance during normal operation, i.e. the problem.
- Section 5.2 discusses a number of issues that have been identified that may have contributed to the degradation of frequency performance during normal operation.
- Section 5.3 summarises the general opportunities for improvement to the existing frequency control frameworks that are likely to address the problem.

5.1 Defining the issues

This section describes the issues that have been identified that relate to frequency control during normal operation, including:

- an overview of the recent degradation of frequency performance during normal operation
- a discussion of the factors identified that may have contributed to the degradation of frequency performance during normal operation.

5.1.1 Degradation of frequency performance during normal operation

Frequency performance under normal operation has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band. This degradation has been documented by AEMO in its recent frequency monitoring reports, along with investigations conducted through the Ancillary Services Technical Advisory Group (ASTAG), and an analysis of frequency control performance in the NEM under normal operating conditions prepared for AEMO by DIgSILENT.[66]

This issue was initially highlighted by Pacific Hydro in its submission to the Commission's Interim Report for the *System security market frameworks review*.[67] In its submission, Pacific Hydro highlighted the extent to which frequency has changed by

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

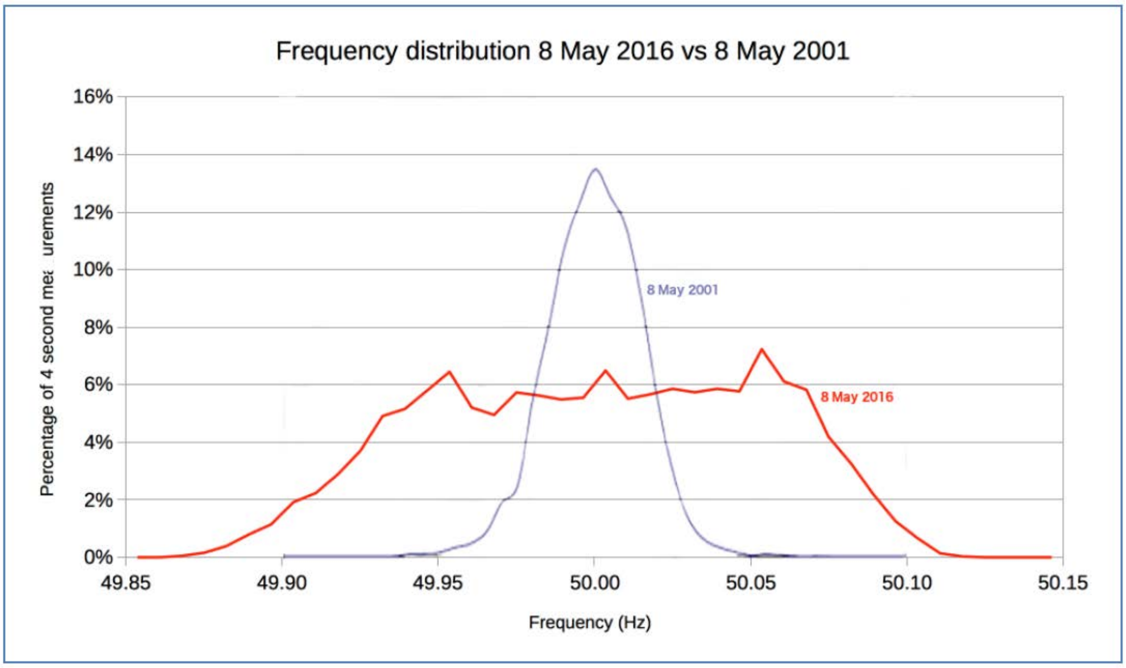
67 Pacific Hydro, submission to *System security market frameworks review* interim report, 6 February 2017.

comparing the system wide frequency profile on 8 May 2016 relative to the same day in 2001.[68]

This comparison is shown below in Figure 5.1. The frequency profile shows the percentage of time that the power system frequency is measured at a given frequency value. The distribution profile for 8 May 2016 shows a clear flattening of the distribution profile relative to 2001.

The Commission notes that, in this example, both frequency profiles demonstrate outcomes that are compliant with the frequency operating standard, in that the amount of time that the frequency is outside of the normal operating frequency band (49.85 – 50.15Hz) is less than one per cent.

Figure 5.1 Frequency distribution profile NEM mainland: 2001 - 2016[69]



The power system frequency has increasingly operated further away from the nominal frequency of 50 Hz than has historically been the case. As a result, the amount of time the frequency is outside the normal operating frequency band in both the mainland and in Tasmania has now exceeded the one per cent requirement of the frequency operating standard on a number of occasions. So far, with the exception of contingency events, the mainland frequency has been maintained within the normal operating frequency band for at least 99% of the time. The one per cent requirement was not met

68 The Commission notes that 8 May in 2001 fell on a Tuesday and 8 May 2016 fell on a Sunday. A typical weekend load profile is likely to be different from a typical weekday load profile.

69 Pacific Hydro, 6 February 2017, submission to *System security market frameworks review* interim report, p. 4.

in Tasmania from February 2016 to February 2018, with the exception of August and September 2016.[70]

DIgSILENT identified a number of consequences of deteriorating frequency control performance, including:[71]

- 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 interconnectors
- 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 primary frequency control due to the added burden on existing primary frequency control.

Additional data on recent frequency monitoring in the NEM along with further detail on the DIgSILENT analysis of this issue, including the consequences of deteriorating frequency control performance and possible causes of the deterioration, is set out in Appendix F.

5.1.2 Drivers of the degradation of frequency control performance

This section sets out the AEMC's understanding of the drivers of the degradation of frequency control performance that have been identified by stakeholders. This includes:

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

70 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017; AEMO 2018, Frequency monitoring and time error reporting – 4th quarter 2017, March 2018.

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

Reduction in frequency response during normal operation

The DIgSILENT analysis indicates that the deterioration of frequency performance during normal operation has largely been caused by generators decreasing or removing their responsiveness to frequency deviations within the normal operating frequency band. It shows that there has been a very significant decline in the amount of primary frequency response provided by generator governors within the normal operating frequency band since the introduction of the FCAS markets and the removal of the compulsory provision of governor response. DIgSILENT concludes that this has had an adverse impact on the performance of frequency regulation within the normal operating frequency band.[72]

This reduction of primary frequency response during normal operation is understood to have taken place gradually over a period of years through generators putting in place changes to their generator control systems including:

- Widening their governor dead band settings out to between ±0.1 Hz and ±0.15 Hz. The effect of this is that the generators that have made this change are unresponsive to frequency changes until the frequency drops below 49.9 Hz – 49.85 Hz or rises above 50.1 Hz – 50.15 Hz.
- Upgrading of older mechanical governors to newer digital control systems. These digital governor control systems enable a generator to easily change the frequency response mode of the generator, and the governor settings such as the dead band and droop characteristics.
- Where it is more difficult or costly to change their governor settings and uneconomic to upgrade to digital systems, the installation of secondary control systems to dampen the primary governor response of their generating units, in favour of maintaining alignment of generator output with dispatch targets. These secondary controllers essentially expand the effective dead band for these generating units to ±0.15 Hz, in line with the normal operating frequency band of 49.85 Hz to 50.15 Hz.

The net result of these changes to generator control systems is a reduction in the level of primary frequency control that contributes to maintaining the power system frequency within the normal operating frequency band (49.85 Hz to 50.15 Hz). The NER requires market participants to obtain AEMO approval prior to changing the frequency response mode and frequency control settings. A detailed discussion of this is included in Appendix E.[73]

A number of generators acknowledge making changes to the governor settings to detune responsiveness to frequency variations. In its submission, AGL confirms that the droop control on the Loy Yang power station has been disabled in order to avoid

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

73 Clauses: 4.9.4(c) and 5.2.5.11 of the NER.

exposure to causer pays events.[74] Similarly Stanwell note that there has been an observed reduction in the provision by generators of a free primary frequency response.[75]

Analysis by DIgSILENT and input from stakeholders, suggests that there are three main issues that are driving generators to decrease or remove their responsiveness to frequency deviations within the normal operating frequency band, including:

- prioritisation of compliance with dispatch instructions over the provision of primary frequency regulation services
- allocation of regulating FCAS costs in accordance with market participant contribution factors under AEMO's causer pays procedure
- desire to limit costs associated with reduced operating efficiency and increased wear and tear on plant.

The following text elaborates on these issues.

Prioritisation of compliance with dispatch instructions

Some stakeholders are of the view that the deterioration in frequency performance is (either partially or entirely) a result of generators reducing or removing their responsiveness to frequency deviations in the normal operating frequency band to 'prioritise' compliance with clause 4.9.8(a) of the NER.[76]

Clause 4.9.8(a) of the NER states that:

> "A Registered Participant must comply with a dispatch instruction given to it by AEMO unless to do so would, in the Registered Participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment."

This clause is a civil penalty provision.

Over the lifetime of clause 4.9.8(a) of the NER, the AER has issued five infringement notices for failure to comply with dispatch instructions, and has instituted proceedings in the Federal Court once (successfully) against Snowy Hydro for a number of breaches of this clause.[77] In its December 2016 quarterly compliance report, the AER stated that compliance with dispatch instructions is a priority area.

74 AGL, submission to issues paper, p. 3.

75 Stanwell Corporation, submission to issues paper, p. 4.

76 Submissions to issues paper: AGL, p. 3; Pacific Hydro, p. 2. See also: Pacific Hydro, submission to *System security market frameworks review* interim report, 7 February 2017, pp. 8-9.

77 Clause 4.9.8(a) of the NER was in version 1 of the NER and was also included in the National Electricity Code, which predated the NER.

In the report prepared for AEMO in September 2017, DIgSILENT reported that "there appears to be a heightened awareness of … compliance with dispatch instructions" as a result of the AER's actions in this area. DIgSILENT noted that some participants believe they are better able to achieve dispatch compliance if they do not have their governors responding to frequency variations.[78] Similarly, DIgSILENT reported that there is a strong belief that adhering closely to dispatch targets will minimise a participant's contribution factors, which are used to determine the allocation of regulating FCAS costs. DIgSILENT concluded that these perceptions, in combination with the fact that there is no obligation for a generator to provide it, may be a contributing factor in the withdrawal of governor response.

This issue of compliance with dispatch instructions is discussed further in section 5.3.1.

Causer pays contribution factors

A principal reason noted by generators for making changes to their governor settings has been to more easily adhere to their AGC targets in an effort to reduce their causer pays contributions.[79]

The aim of the causer pays contribution factor process is to recover costs associated with the provision of regulation services in a way that incentivises market participants to act to minimise the need to procure these services. In order to succeed in this aim, the cost recovery framework needs to transparently and accurately map the allocation of costs to actions that create the need for the regulation services.

The NER sets out that the costs associated with the procurement of regulation services are recovered from market participants based on contribution factors that reflect the extent to which a market participant contributed to the need for regulation services.[80] AEMO determines the "Causer Pays" procedure that sets out how these contribution factors are calculated based on principles set out in the NER.[81] These principles include that:[82]

> “a scheduled participant will not be assessed as contributing to the deviation in the frequency of the power system if within a dispatch interval:
>
> [...]
>
> (iii) the Scheduled Participant is not enabled to provide a market ancillary service, but responds to a need for regulation services in a way which tends to reduce the aggregate deviation;”

---

78 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, 19 September 2017, p. 7.

79 Ibid., p. 30.

80 Clause 3.15.6A(k)(1) of the NER.

81 Clause 3.15.6A(k) of the NER.

82 Clause 3.15.6A(k)(5) of the NER.

This means that a generator that assists with frequency control in such a way that reduces the need for regulation services should not be penalised for providing such a frequency response.[83] The causer pays procedure allows a market participant to offset the operational performance of its generating units that contribute to frequency deviations with that of other generating units within its portfolio that help correct frequency deviations during normal operation. The procedure provides a limited incentive for market participants to operate in a way that supports frequency control.

However, stakeholder submissions to the issues paper noted that AEMO's causer pays procedure is not well understood and does not reflect a participant's contribution to any frequency excursion at the time of that excursion.[84]

AGL noted that if a generator changes its output in response to a frequency event, but AEMO is unable to verify this, the generator is deemed to have not followed dispatch instructions and the causer pays arrangements allocate costs to these generators. AGL submitted that its Loy Yang power station was consistently being exposed to costs under the causer pays framework during frequency events when the governor was in operation. Once the droop control was disabled and the unit allowed to run only at AEMO set-points and to provide FCAS, the number of causer pays events dropped dramatically.[85]

A number of aspects of the existing causer pays procedure have been identified by stakeholders as potentially increasing costs to market participants or resulting in inefficient outcomes. These include:

- a temporal disconnect between a market participant's contribution to the need for regulating FCAS and the costs charged to that market participant
- a lack of transparency and simplicity in the calculation of market participants' costs
- the impact of increasing regulating FCAS costs
- the smearing of residual costs across market customers, which limits the effectiveness of the causer pays arrangements as an incentive to respond efficiently to frequency deviations.

Temporal disconnect between causer pays behaviour and cost recovery

AEMO is required to publish contribution factors with a notice period of at least 10 business days prior to the application of those factors.[86] Currently, AEMO has chosen to adopt a 28-day averaging period for the calculation of the contribution factors as

83 The causer pays procedure does not consider the behaviour of market participants who are enabled to provide regulation services, nor does it apply to power system operation following contingency events.

84 Submissions to issues paper: Meridian Energy, p. 7; Pacific Hydro, p. 11; Snowy Hydro pp. 9,12.

85 AGL, submission to issues paper, p. 3.

86 Clause 3.15.6A(na) of the NER.

outlined in AEMO's causer pays procedure. Taken together with the notice period, this means that the contribution factors are based on performance over a four week period commencing around seven weeks earlier.

The Commission understands that the current causer pays procedure aggregates all of the contribution factors from each generating unit within a generator's portfolio over the 28 day sample period and discards any net positive contribution factors.[87] The intent of this process is that a generator who provides frequency response that assists with frequency control is able to offset that response against any negative contributions within their portfolio and that any participant with a net positive contribution factor will not be liable for contributing towards the cost of regulating services for that period.

The net result of these design characteristics is that there does not appear to be a clear temporal linkage between causer pays behaviour and cost recovery. The 28-day averaging mutes the price signal in any single dispatch, since the measured historic behaviour is used as the basis for recouping future costs that have an unknown magnitude.

Lack of transparency and simplicity in the calculation of costs

It also appears that the basis of the calculation of contribution factors is poorly understood and poorly documented. While AEMO's causer pays procedure outlines the approach used to calculate contribution factors and to allocate costs, it does not provide sufficient details for participants to calculate their own contribution factors. In particular, the calculation of the performance measure uses terms that are not simple to calculate or verify.

The performance measure is defined as the product of the generator output (MW) deviation from the dispatch target and the frequency indicator (FI).[88] The FI factor is designed to indicate the extent to which more generation (in which case it is positive) or else demand (negative) is required in order to keep the frequency at 50Hz. The Commission understands that participants do not know this factor ahead of time and as such are not able to calculate their own causer pays contribution factor in real time in order to inform operational decisions.

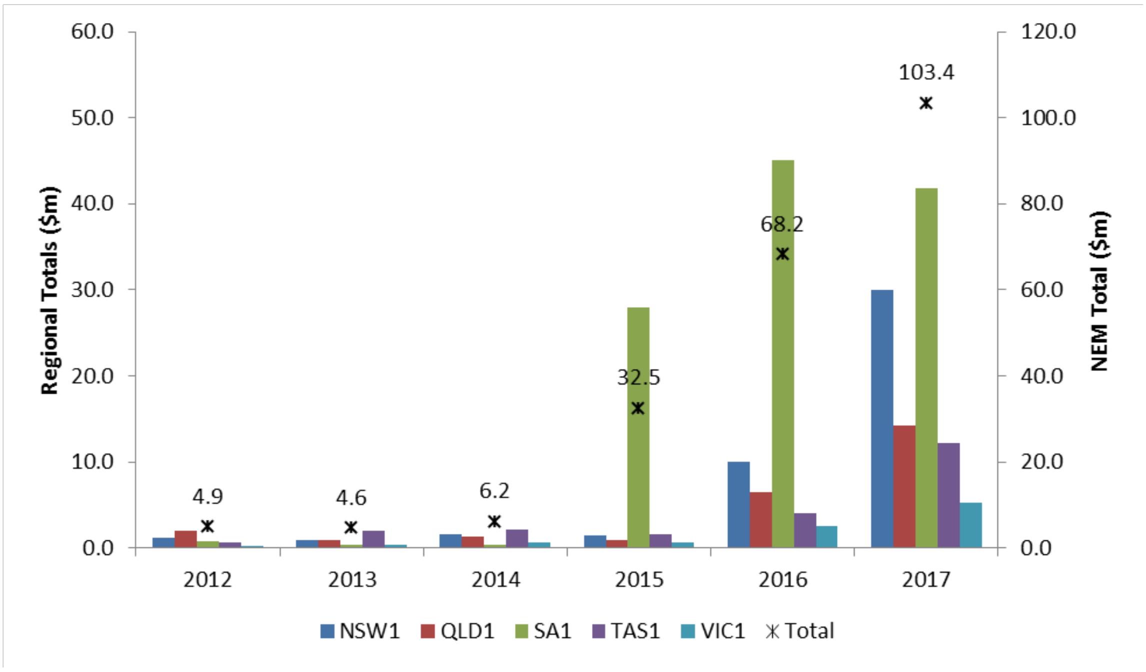
Impact of increasing regulating FCAS costs

Regulating FCAS costs have been increasing dramatically in recent years, from around $5 million per annum in 2011 to over $100 million in the 2017 calendar year (or a 20 fold increase). This is highlighted in Figure 5.2 below.

87 AEMO, Causer pays procedure, 3 March 2017, p. 23.

88 AEMO, Causer pays procedure, 3 March 2017, p. 17 (equation 4).

Figure 5.2 Regulating FCAS costs 2012 - 2017



The above chart highlights that the increase in regulating FCAS costs principally occurred from 2015 to 2017 and that while all regions have contributed to that increase, the main contributing regions have been South Australia and NSW. While AER high FCAS price reports suggest that the South Australian outcomes are at least in part due to occurrences where interconnection was constrained and a local regulating FCAS requirement applied (with subsequent rebidding indicating use of temporary market power), the explanation for the NSW outcome is less clear.

The increase in regulating FCAS costs over this period is partly explained by the underlying increase in wholesale energy market prices (with the total value in this market approximately doubling over this period) from $6 billion in 2011/12 to some $11.7 billion in 2016/17. However, this increase is substantially lower than the approximately 20 fold increase in the value of the regulating FCAS market.

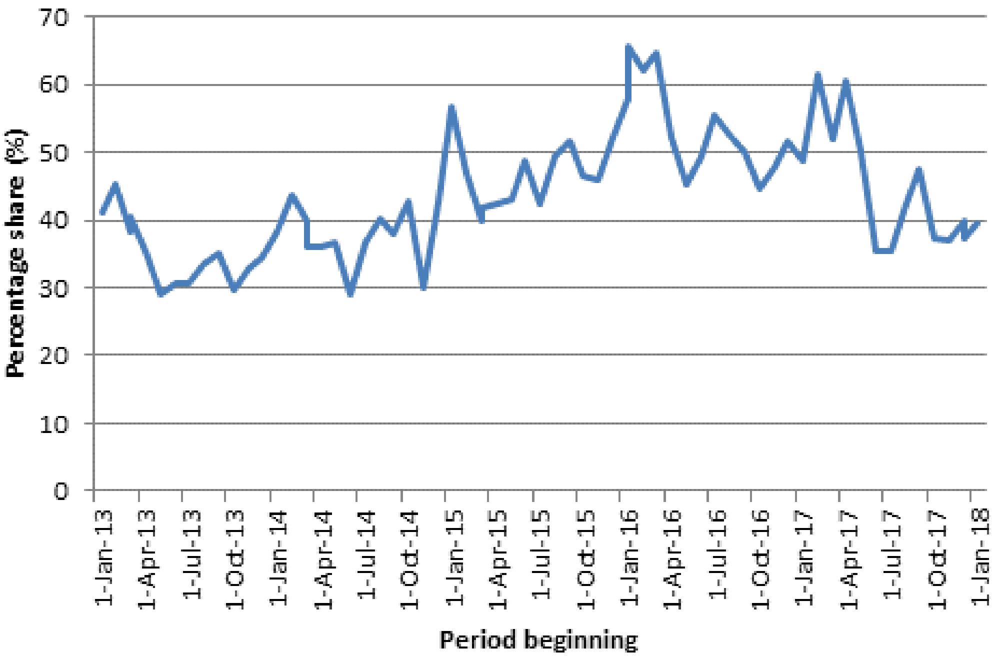
This increase in regulating FCAS costs has had the effect of heightening market participants' concerns with the regulating FCAS causer pays cost recovery framework as the magnitude of actual and potential causer pays charges has increased dramatically in recent years.

Causer pays residual allocation impact

Under the causer pays procedure, any amount not recovered from market participants is recovered from market customers without a contribution factor in proportion to energy consumed by them over the 28-day sample period. This smearing of residual regulating FCAS costs does not appear to have any positive incentive effect on the behaviour of market participants given that market customers are unable to influence the share of such costs they bear other than through reducing consumption.

The share of regulating FCAS costs borne by scheduled generators is currently around 40% having declined from a five year peak of around 65 per cent in January 2016 as highlighted in Figure 5.3. The Commission notes that while frequency performance during normal operation has degraded, generators have not borne any increased share of the costs associated with regulating FCAS. Therefore, to the extent that the degradation of frequency performance during normal operation is due to generator performance, the decline in associated causer pays share of regulating FCAS suggests that the incentive role of causer pays is not effective.

Figure 5.3 Regulating FCAS generator causer pays share (2013 to 2017)



Reduced efficiency and increased wear and tear on plant

The DIgSILENT investigation noted reports from generators that the provision of primary frequency response through the maintenance of narrow governor settings within the normal operating frequency band incurs costs in the form of reduced operational efficiency and increased wear and tear.[89]

The Commission understands that these costs relate to the impact of operating the generating plant in a mode that is responsive to frequency variations within the normal operating frequency band, 49.85Hz – 50.15Hz. Thermal generators that vary their generation output in response to changes in frequency are less able to maintain maximum operating efficiency. Additional operational variation leads to an increase in cycling loads on generation plant and can lead to an incremental increase in fuel consumption per MW of generation output.

89 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, 19 September 2017, p. 42.

Regulating FCAS and the AGC system

Through the ASTAG, stakeholders have raised concerns that the operation and performance of regulating FCAS and the AGC system may be contributing to the degradation of frequency performance during normal operation.

Under the NER, AEMO can purchase regulating FCAS via the regulating raise and regulating lower ancillary services markets. The goal of the regulating raise and lower services is to maintain the power system frequency within the normal operating frequency band defined in the frequency operating standard.[90] The AGC is a centralised system that continuously monitors the power system frequency and sends out electronic signals to generators enabled in the regulation service markets to "raise" or "lower" their generation or load to correct small frequency deviations during normal operation.

Snowy Hydro has suggested that AEMO have not been enabling a sufficient quantity of regulating FCAS to rectify errors in semi-scheduled generation forecasting.[91]

The existing quantity of global regulation raise has a base component of 130MW and 120MW for lower and a variable additional component that is procured based on the level of accumulated time error. Currently, the maximum value of regulation raise and lower is capped at 250MW.[92]

The Commission notes that a record of the historical changes in the global quantity of regulation raise and lower services is found in the documentation for the NEMMCO FCAS review that was completed in July 2007. The base quantity for global regulation raise and lower services was progressively reduced from 250MW prior to July 2003 to 130MW for global regulation raise and 120MW for global regulation lower from June 2006.[93] Separate requirements are set for electrically islanded regions, if required. At the time, NEMMCO analysis found that a reduction in the quantity of global regulation services would not significantly impact the chance of the frequency exceeding the normal operating frequency excursion band.[94]

Stanwell noted in its submission to the issues paper that frequency performance improved in May and June 2017 following changes to the AGC settings by AEMO. Stanwell proposed a number of areas for further consideration in relation to the AGC system and regulating FCAS. These include:[95]

---

90 Chapter 10 of the NER defines the regulating raise(lower) service as: "The service of controlling the level of generation or load associated with a particular facility, in accordance with the requirements of the market ancillary service specification, in accordance with electronic signals from AEMO in order to raise(lower) the frequency of the power system."

91 Snowy Hydro, submission to issues paper, p. 5.

92 AEMO, Constraint Implementation Guidelines, June 2015, p.27.

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

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

95 Stanwell Corporation, submission to issues paper, pp. 7-8.

- consideration of an increase in the quantity of regulation raise service from the current base of 130MW, noting that following the inception of the FCAS market in 2001, the quantity of regulation raise was originally set at 250MW
- an investigation of the frequency regulation interactions between the mainland NEM and Tasmania via the Basslink frequency controller
- improved verification of generator response to AGC regulation signals and the notification or removal of non-conforming units from regulation dispatch.

A number of stakeholders supported greater transparency around the AGC system. For example, Snowy Hydro suggested that the AGC system design and operation in its current form is opaque.[96] It proposed an independent and detailed assessment of the key inputs to the AGC system, including discussion of how it works and the changes required to support better frequency management.

Engie highlighted ongoing work by the ASTAG into the potential contribution of the AGC system and its interaction with Basslink (among other factors), to the degradation of frequency performance across the NEM.[97]

The Commission notes that, as documented through the ASTAG, AEMO is currently reviewing the settings and operation of the AGC and regulating FCAS.[98] Further discussion of potential improvements to AGC and regulating FCAS is included in section 5.3.1.

5.2 Assessment of materiality

As part of the *Frequency control frameworks review*, the Commission has considered the need for the increased provision of primary frequency control to improve the recent degradation in frequency performance under normal operating conditions.

As set out in section 5.1, frequency performance under normal operation has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band.

The power system frequency has increasingly operated further away from the nominal frequency of 50 Hz than has historically been the case. As a result, the amount of time the frequency is outside the normal operating frequency band in both the mainland and in Tasmania has now exceeded the one per cent requirement of the frequency operating standard.[99]

---

96 Snowy Hydro, submission to issues paper, p. 5.

97 Engie, submission to issues paper, p. 2.

98 AEMO, ASTAG meeting pack, Item 5, 27 November 2017.

99 For October 2017, the mainland frequency was maintained within the normal operating frequency band for 98.91 per cent of the time. Similarly, the one per cent requirement has not been met in Tasmania from February 2016 to June 2017, with the exception of August and September 2016.

The Commission notes that the frequency operating standard provides guidance as to what constitutes 'good frequency performance' in the NEM. However, based on the work undertaken by DIgSILENT, and through discussion with stakeholders, the Commission considers there to be a number of additional attributes of ‘good frequency performance' that are likely to have some technical benefits through the provision of a more stable system.

The Commission requested AEMO to provide technical advice on a number of aspects of frequency performance under normal operating conditions, including:

- the operational benefits of primary response during normal operation, independent of headroom capacity
- the geographical location of primary frequency response and the benefits of a system wide distribution
- the frequency responsiveness capabilities of the existing fleet
- the interactions of primary and secondary control in relation to controlling frequency and the extent to which these responses are substitutable

Based on AEMO advice, the Commission has concluded that the provision of primary frequency control is likely to have technical benefits through the delivery of a more stable power system.[100] The Commission notes that:

- increasing the level of primary response in the system can have a significant effect on the extent to which system frequency can be maintained within target range
- there is a limited ability to use regulating FCAS as a substitute for primary frequency control. Similar amounts of each service are required to correct minor imbalances in supply and demand
- there are benefits from a broad distribution of primary frequency control throughout the power system, including increased resilience to non-credible contingency events

However, the provision of primary frequency control has an associated cost. In order to support the provision of an increase in primary frequency control, it must be demonstrated that these costs are likely to be lower than the benefits arising from an improvement in frequency performance. Specifically, any changes to the frameworks for the provision of frequency control within the normal operating frequency band must be consistent with the NEO.

This section:

- provides a description of how the Commission interprets 'good frequency performance'

- summarises the technical advice prepared by AEMO for the review. The AEMO advice covers the role of primary and secondary control services to achieve good frequency control and provides an outlook for frequency control challenges over the next 15 years
- provides a discussion of the economic factors relating to frequency control during normal operation, including a description of the costs and benefits of providing primary frequency control

5.2.1 Good frequency performance

The Commission considers that the goal of frequency control during normal operation – that is, in the absence of any contingency event – is to maintain the power system frequency close to 50Hz for the majority of the time. The specific performance standards for frequency are determined by the Reliability Panel and set out in the frequency operating standard.

Good frequency control should meet the requirements of the frequency operating standard. However, the Commission also considers there to be a number of additional attributes of good frequency control. In order to deliver a relatively stable power system:

- frequency should be close to 50Hz for the majority of the time
- frequency deviations should be corrected in a relatively short period of time
- the system should be free from undamped frequency oscillations
- changes in frequency over time should be relatively slow and smooth

Having arrangements in place that control and maintain a stable system frequency within a narrow range, close to 50Hz has the following advantages:

- It supports the safe and secure operation of the power system.

  The safe and secure operation of the power system is based on AEMO's ability to accurately model and predict the behaviour of power system elements under expected operating conditions, including the system frequency. AEMO's power system models are based on the assumption that the system frequency is 50Hz. Therefore, a change in the system frequency may lead to a reduction in the accuracy of AEMO's power system models that underpin the ability of the dispatch process to maintain power system security. The goal of this process is to dispatch generation within the technical capabilities of the power system elements to meet the expected load. This issue was noted in the Pacific Hydro submission to the issues paper.[101]

---

100 AEMO, Response to request for advice - Frequency control frameworks review, 5 March 2018.

101 Pacific Hydro, submission to issues paper, 5 December 2017, pp. 2,8.

- It increases the resilience of the system to non-credible contingency events.

  The availability and provision of primary frequency response from a diverse number of generating units in the power system helps to stabilise the power system following non-credible contingency events.

  In the event of a severe non-credible or multiple contingency event, any primary frequency response from any connected generator may be instrumental in avoiding some load shedding and increase the likelihood that the system will recover from the event. An example of such an event occurred on 13 August 2004, when the failure of a transformer at the Bayswater switchyard led to the loss of six generating units in New South Wales totalling 3100MW.[102] Following this event the level of frequency response provided throughout the NEM was between two and seven times the enabled amount, as measured in terms of the fast, slow and delayed raise services.[103]

- It supports accurate demand forecasting.

  The actual demand in the power system can vary as a consequence of changes in system frequency. Therefore a stable frequency close to 50Hz is likely to reduce demand forecasting errors due to the variable nature of demand with respect to frequency.[104] The Commission understands that the current estimate for this variation, referred to as load relief, is 1.5 per cent (1 per cent in Tasmania) for each 0.5Hz change in frequency. Therefore, if the frequency goes from one extreme of the normal operating frequency band to the other (e.g. 50.15Hz to 49.85Hz) the demand would be expected to change by 0.9 per cent, or by about 300MW for a NEM-wide demand of 33GW. This would increase to about 450MW for a frequency change of 50.25Hz to 49.75Hz, i.e. the range of the normal operating frequency excursion band.

- It may reduce the wear and tear on synchronous generators that are responsive to changes in system frequency.

  A lower volatility in system frequency may lead to reduced wear and tear on synchronous generation equipment caused by the cycling of equipment speeding up and slowing down as the frequency changes.

- It supports the synchronisation of synchronous generation equipment to the power system.

102 NEMMCO, Power system incident report – Friday 13 August 2004: final report, 28 January 2005, p. 8.

103 Ibid., p.14.

104 AEMO, Constraint Implementation Guidelines, June 2015, p. 20.

The ability for generators to synchronise and connect with the power system is important for bringing capacity to the electricity market which strengthens competition and supports reliability of supply.[105]

5.2.2 Technical assessment

In order to determine whether there is a need for making changes to the frameworks, the Commission has assessed the technical benefits of an increase in the provision of primary frequency control in order to deliver 'good frequency performance'.

This section sets out the Commission's assessment based on technical advice received from AEMO, work undertaken to date by DIgSILENT, and discussions held with stakeholders.

AEMO advice

The Commission requested AEMO to provide technical advice on a number of aspects of frequency performance under normal operating conditions, including:

- the operational benefits of primary response during normal operation, independent of headroom capacity
- the geographical location of primary frequency response and the benefits of a system wide distribution
- the frequency responsiveness capabilities of the existing fleet
- the interactions of primary and secondary control in relation to controlling frequency and the extent to which these responses are substitutable.

With respect to these aspects, AEMO's advice notes that:

- The amount of primary frequency control that is active in the power system plays an important role in determining the extent of the frequency deviation for a given supply demand imbalance. Increasing the level of primary response in the system can have a significant effect on the extent to which system frequency can be maintained within the target ranges set out in the frequency operating standard.[106]
- There is limited ability to substitute between primary and secondary control services and similar amounts of each are required to correct temporary imbalances between supply and demand. However, while secondary response

105 At the ASTAG meeting for synchronous generators held on 11 October 2017, some generators noted that the process of synchronising generators to the network is becoming more difficult due to increased variability of power system frequency within the normal operating frequency band. While this is plausible, the effect and the materiality of it have not been confirmed by AEMO.

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

does not reduce the maximum size of the frequency deviation, it is required to support the restoration of frequency to 50 Hz following a deviation.[107]

- There are benefits from a broad distribution of primary frequency control throughout the power system, including increased resilience to non-credible contingency events and islanding events.[108]

- AEMO is required to procure regulating FCAS to maintain the frequency within the normal operating frequency band (49.85Hz – 50.15Hz) for 99 per cent of the time. Importantly, the frequency operating standard does not require AEMO to restore the frequency to the nominal value of 50Hz. If the frequency operating standard required AEMO to restore the frequency to 50Hz from the edge of the normal operating frequency band, AEMO may procure more regulating FCAS than is currently the case.[109]

The AEMO advice also provides an outlook for frequency control in the NEM over the next 15 years in line with AEMO's National Transmission Network Development Plan.

The AEMO advice is published on the project webpage. A summary of the AEMO advice is provided in Appendix D.

5.2.3 Economic assessment

The assessment set out above demonstrates the technical benefits of increased primary frequency response in improving frequency performance under normal operating conditions. In line with the findings of the DigSILENT report, the economic benefits of improved frequency performance are likely to include:[110]

- a slight reduction in maintenance costs and fuel costs of synchronous machines that are responsive to frequency variations

- increased resilience of the power system to contingency events which is likely to reduce the costs associated with unserved energy due to the operation of emergency frequency control schemes such as under frequency load shedding.

However, an increase in the provision of primary frequency control would come at a cost. In order to support the provision of an increase in primary frequency control, it must be demonstrated that these costs are likely to be lower than the benefits arising from an improvement in frequency performance.

107 Ibid.

108 Ibid. pp. 5-6.

109 Ibid. pp.12-13.

110 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, section 5.3.

Any changes to the framework for frequency control within the normal operating frequency band must be consistent with the NEO – that is, be in the long term interests of consumers of electricity.

The costs of providing primary frequency response include the direct costs incurred by providers of the service as well as the opportunity costs where a generator is required to withhold generation from the energy market in order to be able to provide a frequency response.

While the Commission has attempted to broadly evaluate these costs and benefits, a detailed quantification of these costs and benefits has not been undertaken at this time. Such an assessment would require detailed power system modelling along with an estimation of the cost impacts on each individual generator in the NEM. Given the observed and immediate degradation of frequency performance during normal operation the Commission has employed a principles-based approach to the assessment of potential changes to frameworks for frequency control.

The Commission recognises that there is both a technical and an economic interaction between primary frequency control and secondary frequency control procured through regulation services in order to manage the frequency in the NEM during normal operation. To some extent, additional primary frequency control could complement or be a replacement for a proportion of the current regulating FCAS procured in the NEM.

However, advice received from AEMO suggests that, in general, primary frequency response and regulating FCAS serve different purposes and there is unlikely to be a significant trade-off between these services.[111] There is however a need for AEMO to optimise the amount of primary and secondary response in order to meet the requirements of the frequency operating standard at the lowest cost.

Under the current arrangements, AEMO can only procure additional secondary response through the regulation service markets. AEMO has limited powers to change the quantity of primary response that is active in the power system. As such, the following discussion deals with the costs of providing primary frequency control in order to address the observed degradation of frequency performance during normal operation.

Costs of providing primary frequency control

Costs associated with the provision of primary frequency control include:

- direct cost impacts associated with being frequency responsive
- opportunity costs associated with foregone generation where a generator is required to maintain headroom to provide a response.

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

Direct costs

Direct costs may include:

- increased fuel consumption related to variable output as the generator responds to frequency variations
- increased variable operation and maintenance costs, due to potentially working the generator harder as it follows frequency variations.

Accurate quantification of these direct costs is impractical as it would require detailed analysis of the operations of each generating unit operating in the NEM. However, work undertaken by DIgSILENT would suggest that the cost impact from providing frequency response on any single unit is likely to be small, provided all technically capable generating units are frequency responsive.[112]

The direct costs of providing frequency response are likely to be proportional to the quantity of response provided in MW over a certain period. That is, the proportional size of the additional maintenance and fuel costs for each additional MW of response is likely to be relatively constant. The DIgSILENT report noted that one participant estimated the scale of additional fuel costs may be in the order of 0.5%.[113]

The AEMC has received advice from Nick Miller that the operational costs associated with the provision of primary frequency response by synchronous generation units are likely to be negligible when compared to other factors like variation in fuel price.[114] This view is supported by detailed analysis of the technical and economic impact of increased wind and solar penetration on the US electricity grid for the National Renewable Energy Laboratory. Mr Miller indicated that, based on discussions with US colleagues at ERCOT and the New England ISO, concerns about the cost of providing primary frequency response seem to be almost absent in the US to date. Mr Miller also indicated that the issues of cost and efficiency are detailed and subtle, and that any high resolution analysis of the direct costs associated with the provision of primary frequency response are likely to be expensive and plant-specific.[115]

Opportunity costs

Energy opportunity cost is incurred where a generator is required to lower its output below what it would otherwise have been in order to ensure the ability of the

---

112 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, 19 September 2017, p. 51.

113 Ibid., p. 42.

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

115 Nick Miller, Advice on the costs of primary frequency regulation, 20 March 2018.

generating unit to provide frequency raise support. The magnitude of this opportunity cost reflects the price in the energy market at the time that headroom is required to be provided. A complication here is that some headroom can be provided by some generators above their maximum economic dispatch which means that for certain levels of response, their opportunity cost is zero. However in the case of wind and solar PV generators, under normal operating conditions, the opportunity cost is the forgone power production, plus other benefits like renewable credits.

The opportunity cost of providing headroom is likely to increase as the quantity of frequency response increases over a certain period. In addition the opportunity cost of maintaining headroom will be sensitive to the exact time that the response is required. The factors driving this relationship are the commitment level of the generating unit at any point in time, as a proportion of it maximum capacity, and the price in the wholesale electricity market. Therefore if a generator were required to provide a relatively small amount of headroom for response, as a proportion of unit capacity, and if there was flexibility as to the exact timing of the provision then the associated opportunity costs may be relatively low. On the other hand, the opportunity costs would increase where the required headroom for response is increased, as a proportion of unit capacity, and flexibility for the timing of the provision is restricted.

A function of the existing markets for ancillary services in the NEM is to maintain headroom for the purpose of regulation and contingency FCAS. A key issue for the provision of primary frequency control during normal operation is whether the benefits of maintaining headroom outweigh the costs of that headroom, including the opportunity costs discussed above.

5.2.4 Conclusion of the assessment of materiality

The frequency performance in the NEM has degraded in recent times. While a number of contributing factors have been identified in relation to this degradation, the investigation by DIgSILENT and the AEMO advice supports the case that a reduction in active primary frequency control within the normal operating frequency band (49.85Hz – 50.15Hz) is the dominant driver of the observed degradation.[116] Therefore, the Commission is considering changes to the frequency control frameworks in the NEM to help restore and maintain good frequency performance now and into the future. The proposed changes include improvements to existing arrangements associated with regulating FCAS along with changes to incentivise or require the provision of primary frequency response within the normal operating frequency band.

In relation to the consideration of potential mechanism to incentivise or require the provision of primary frequency response, the Commission has investigated the approach of various international jurisdictions including the United Kingdom, Ireland, Texas USA and New Zealand. Case studies summarising the frequency control arrangements in each of these jurisdictions, including any arrangements for the provision of primary frequency control are included in Appendix G. The Commission

116 Ibid. p. 6.

notes that some arrangement for the provision of primary frequency control during normal operation, or governor response, is common to the power system operational arrangements in each of these jurisdictions. Ireland and the UK each have arrangements for incentive payments for the provision of primary frequency response, whereas primary frequency response is required to be provided free of charge in New Zealand and Texas.[117]

Ideally, the economic assessment of potential solutions to improve frequency performance during normal operation would be based on a clear understanding of the nature and magnitude of the costs and benefits of the proposed changes. As a basis for this assessment, the Commission considers that where a change to the regulatory or market arrangements is likely to drive an improvement in frequency performance at little or no additional cost, then such a change is likely to be consistent with the NEO. However, due to the lack of available detailed data at this time, the Commission has applied a principles-based approach to the assessment of policy options as set out in section 5.3.

5.3 Options available to address the issues

The Commission has identified two main focus areas for improvement of the frequency control arrangements to address the identified issues relating to frequency regulation during normal operation.

Improved transparency

Stakeholders have expressed concern with a general lack of transparency around key processes relating to frequency control in the NEM work, including:

- AEMO's arrangements for determining the recovery of regulating FCAS costs (the causer pays procedure)
- AEMO's AGC system and the provision of regulating FCAS

Section 5.3.1 discusses improvements to the causer pays procedure and AGC system, including improvements to the level of transparency and understanding of these processes.

These improvements to existing frameworks are likely to provide benefits irrespective of the recent decline in power system frequency performance, but may not provide a complete resolution to the issues.

117 The New Zealand electricity authority is in the process of undertaking a strategic review of normal frequency management. This review is considering potential arrangements to incentivise the provision of primary (governor) response. NZ Electricity Authority, Normal Frequency Management Strategic Review: Information paper, March 2017, p. 25.

Adequate incentives for the provision of primary frequency control during normal operation

The Commission recognises that the current regulatory arrangements do not adequately incentivise the provision of primary frequency control response to assist in frequency regulation during normal power system operation. Sections 5.3.2 and 5.3.3 discuss the Commission's assessment of a range of options that are likely to incentivise the provision of primary frequency control during normal operation.

5.3.1 Improvements to existing frameworks

Analysis of the potential causes of the recent degradation of frequency performance has highlighted a lack of transparency around how the existing frequency control arrangements in the NEM work.

Stakeholders have expressed concern with a general lack of clarity of key processes relating to frequency control in the NEM, including:

- AEMO's AGC system and the arrangements for the activation of regulating FCAS
- AEMO's arrangements for determining the recovery of regulating FCAS costs (the causer pays procedure)
- the requirements in the NER relating to compliance with dispatch instructions.

The following section discusses the range of issues which have so far been identified in relation to the first two sets of arrangements and outlines a number of proposals for where improvements could be made to the transparency and effectiveness of these procedures.

In many instances, resolution of these issues through changes to existing arrangements may provide benefits irrespective of the recent decline in power system frequency performance during normal operation. However, it is also likely that these improvements will not provide a complete resolution to the decline in power system frequency performance and, as such, will likely need to be implemented in addition to alternative policy measures to improve the provision of primary frequency control.

In relation to the third issue concerning compliance with dispatch instructions, the Commission understands that a perceived inconsistency between clause 4.9.8(a) of the NER and the requirements of schedule 5.5.5.11 has contributed to the actions by generators which has resulted in removal or detuning of governor response. However, as set out below, the Commission does not consider that changes to the NER would be appropriate to address this perceived inconsistency and that alternative changes to market frameworks would be preferable to achieve improved frequency response.

AGC and regulating FCAS

Regulating FCAS is provided by generators that are enabled through the regulating raise and regulating lower ancillary service markets. Generators who are enabled to provide regulating services respond to electronic signal sent via AEMO's automatic generation control system (AGC).[118] Part of the function of the AGC is to monitor the system frequency and to send signals out to generators to raise or lower their generation output to maintain the frequency within the normal operating band of 49.85Hz to 50.15Hz.[119] The Commission understands that, while AGC and regulating FCAS are not a substitute for primary frequency control, there are number of opportunities to improve frequency regulation during normal operation through incremental improvements to the performance of regulating FCAS and the AGC.[120] These improvements relate to the following:

- publication of AGC functionality
- improvements to AGC
- varying the base and additional variable quantity of regulating FCAS.

Publication of a description of the AGC functionality

A number of stakeholder submissions to the Issues Paper expressed concerns relating to the transparency of the operation of the AGC. Snowy Hydro noted that the AGC system and processes are opaque and requested that an independent and detailed assessment of the key inputs to the AGC be undertaken along with the preparation of a process map of how the system works and a description of areas for potential improvement.[121] Similarly, Meridian Energy recommended that all available data on the calculation methodology undertaken by the AGC, causer pays and the Australian wind energy forecasting system (AWEFS) be published to allow stakeholders to interrogate these processes and where possible identify opportunities for improvement.[122]

---

118 Clause 3.8.21 of the NER outlines AEMO's obligation to issue dispatch instructions via the online dispatch process. Clause 3.8.21(d) states that “where possible, dispatch instructions will be issued electronically via the automatic generation control system or via an electronic display in the plant control room (which may be onsite or offsite) of the Scheduled Generator, Semi-Scheduled Generator or Market Participant (as the case may be).”

119 AEMO, Guide to ancillary services in the National Electricity Market, April 2015, p. 6.

120 The DIgSILENT report noted that AEMO's AGC system is not designed to be able to make up for the reduction in primary frequency control. In its current form, the AGC system is capable of responding to generation and demand imbalances within approximately 30 seconds whereas primary frequency control is able to respond almost immediately to frequency deviations based on local frequency measurement and automatic response through the generator governor control systems. The AEMO advice to this review provides a detailed comparison of the characteristics of primary and secondary frequency control.

121 Snowy Hydro, submission to issues paper, p. 5.

122 Meridian Energy, submission to issues paper, p. 2.

The final report by DIgSILENT noted that:[123]

> "The overall coordination of regulation frequency control in the NEM may be improved if the generators understand how AEMO's systems work and AEMO understands better how the generators' systems work."

The Commission notes that the NER, requires that AEMO must fully document the processes that relate to the online central dispatch process, including the software, algorithms and principles applied in making judgements where they are required in the process and provide this information to Market Participants at a cost reflective price.[124]

The recent report by DIgSILENT includes a summary of the AGC process and key variables based on AEMO's internal AGC documentation, *Automatic Generation Control Basic Description V2*.[125]

The Commission considers that the publication by AEMO of a technical guide on the operation of the AGC system would likely provide greater transparency to market participants and result in more efficient outcomes.

Improvements to the AGC

Potential improvements to the operation and performance of the AGC were the subject of a presentation by AEMO to the ASTAG on 28 November 2017.[126] The potential areas for improvement identified by AEMO include:

- Frequency bias setting

  Frequency bias is a characteristic of the power system that describes the relationship between the size of a power imbalance and the corresponding change in frequency. Frequency bias is measured in MW per hertz. This value is used by the AGC as a factor to convert a frequency deviation into the increase or decrease in generation required to return the frequency to 50 Hz. This required increase or decrease in generation is referred to as the area control error (ACE). The current frequency bias used by AEMO for mainland AGC is -2800MW/Hz and has remained unchanged for many years. The frequency bias for the Tasmanian AGC is independently set at -200MW/Hz, reflecting the smaller size of the Tasmanian system.[127]

---

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

124 Clause 3.8.21(l) of the NER.

125 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, pp.15-19, 53.

126 AEMO, ASTAG meeting pack, Item 5, 27 November 2017.

127 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 17.

It is possible that an update to the frequency bias setting may allow for a more accurate representation of the generation change required to rectify power system frequency deviations.

- AGC regulation gain settings & low pass filter constants

  The AGC includes a number of settings that modify the sensitivity of the system to variations in ACE. These settings include gains or factors that are applied to the ACE and the integral of ACE to modulate the output in terms of the desired quantity of regulation service.[128]

  The AGC also includes a low pass filter which effectively decreases the sensitivity of the AGC regulation signal to rapid changes in frequency. The low pass filter can be set using different time constants depending on the degree of sensitivity required from the AGC. The DIgSILENT report noted that a typical low pass filter time constant is 32 seconds.

  A review of the gain settings and low pass filter constants may be useful in calibrating the sensitivity of the AGC system to reflect the current characteristics of the power system.

- Coordination between mainland and Tasmania

  The mainland and Tasmanian power systems operate independent AGC systems for frequency control. The two systems are connected via the high voltage direct current – Basslink - interconnector which allows power to flow between the two systems. While Basslink does not provide a synchronous connection, it does operate with a frequency controller which modulates the current flow to attempt to lock the frequency of the Tasmania system with that of the mainland.[129] The Basslink frequency controller also enables the transport of regulation and contingency FCAS response between Tasmania and the mainland.

  AEMO's recent frequency monitoring report, published on 9 August 2017 described the impact of changes to AGC settings on the frequency performance in Tasmania and the NEM mainland following the Basslink outage from January 2016 to July 2017. The frequency performance in the NEM showed a marked improvement in May and June 2017, following a period of steady decline from November 2016 to April 2017. The frequency performance during this period demonstrates the importance of revising the AGC settings to match changes in the power system.

The Commission understands that AEMO is actively reviewing the AGC settings in order to achieve improved AGC performance.[130] The Commission support AEMO's efforts to improve the AGC system to support frequency control in accordance with the frequency operating standard.

128 Ibid.

129 The Basslink frequency controller is an optional operating feature that can be turned off if required.

Varying the base and additional variable quantity of regulating FCAS

AEMO are currently investigating the option of increasing the base amount of regulating FCAS that is procured in the mainland at all times (the static component), as well as adjusting the condition under which additional amounts of regulating FCAS are dispatched in response to larger frequency deviations (the dynamic component). The Commission is supportive of AEMO investigating these changes.

The Commission recognises that while the purchase of additional regulating FCAS may improve frequency performance during normal operation, regulating FCAS is not a perfect substitute for primary frequency control. Under the current arrangements regulating FCAS provides a delayed and secondary response to control system frequency. This response is coordinated through AEMO's AGC system which sends out electronic signals to enabled generators to raise or lower their active power demand to correct slow moving frequency deviations away from 50Hz. As the response time for this current regulating service is in the order of 30 seconds, effective control of rapid variation of supply and demand requires a combination of fast acting primary response as a complement for the centrally controlled secondary response.[131] The interaction between primary and secondary response for regulating frequency during normal operation is discussed in detail in AEMO's technical advice for this review.

Recovery mechanism for regulating FCAS costs – Causer pays

The aim of the causer pays cost recovery arrangements for ancillary services is to provide a price signal that incentivises market participants to act in a way that minimises the need to procure these services. However, when participants are not confident with the approach used to recover costs, the incentives may be muted or unintended consequences may occur.

Removing the inter-temporal disconnect discussed in section 5.1.2, implies the need to align the period over which contribution factors are calculated with the period over which the regulating FCAS costs are incurred and recovered. In addition, given that the frequency variations that regulating FCAS is designed to address occur within the five minute dispatch interval, a more focused incentive would require a dramatic reduction in the averaging period, ideally down to a single dispatch interval. As noted in section 5.1.2, the NER require AEMO to prepare and publish a procedure for determining contribution factors for each market participant. These principles are flexible and provide AEMO with discretion to determine over what period of time to calculate an individual market participant's contribution to the aggregate need for regulation services, such as the use of a single dispatch interval as the relevant period.

---

130 AEMO, ASTAG meeting pack, Item 5, 27 November 2017.

131 The nature of the existing AGC controlled regulating FCAS to be an imperfect substitute for primary frequency control was outlined in the DIgSILENT report, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 6.

The requirement for AEMO to publish these contribution factors at least 10 business days prior to their application means that there would still be a significant delay in notifying market participants of their causer pays obligations.

An issues paper for causer pays procedure consultation was published by AEMO in December 2016.[132] The paper is the first stage of the consultation process to consider amendments to the causer pays procedure. In this paper, AEMO considered changes to the size and timing of the sample period. AEMO's preferred approach is to adopt a seven-day averaging period with possible removal of the 10 business day notice period. They do not support a move to real time factors due to issues related to the availability of accurate SCADA data and concerns over the practical impact on incentives and generator behaviour.[133]

At the *Frequency control frameworks review* technical working group meeting held on Wednesday 17 January 2018, participants argued that any SCADA data issues should be able to be resolved and that this should not be a constraint on the approach adopted. However, there was no clear support for a particular averaging period.

In AEMO's presentation at the working group, they flagged two possible changes arising from the causer pays review, namely:

- removal of periods where primary response opposes AGC direction
- publication of FI (frequency indicator) data near real time.

These are relatively minor changes. While excluding periods where response opposes AGC direction appears sensible, and is likely to remove one potential incentive to act in a way that supports frequency control, the more timely publication of FI data appears of limited value given the continuation of the long averaging period and lack of alignment of causation and recovery periods.

AEMO in its issues paper argued that real-time factors may break cost-to-cause connection because the enabled regulating FCAS volume does not change based on 5-minute system performance, but is rather based on the longer term frequency performance of the system. The Commission considers that a relatively fixed volume requirement is not a detriment to an effective price signal for market participants as at any point in time, they will be able to calculate the total cost of regulating FCAS (based on the known level to be purchased and the marginal price set in the market) and therefore can determine an efficient response from their perspective in terms of choosing their level of frequency responsiveness. Just as at present, to the extent that all generators respond in such a way so avoid negative contribution factors, then the cost of procuring regulating FCAS will be passed through to market customers in proportion to their energy demand in the relevant period. Presumably, in such circumstances frequency control will be substantially improved and may impact on the volume required and possibly the cost.

132 AEMO, Causer pays procedure consultation, Issues paper, December 2016.

133 Ibid, p. 13.

To achieve the aim of the cost recovery of the ancillary services stated above, and taking into account the issues described, the Commission considers that there would likely be benefits in aligning the average period used for calculation of contribution factors with the period over which the costs are incurred over a reasonable time interval. The Commission considers that the calculation of contribution factors should be based on the five-minute dispatch interval to achieve consistency with the energy market. The Commission also considers that the requirement in clause 3.15.6A(na) of the NER for a ten business day notice period between AEMO publishing and applying contribution factors could be removed.

Draft recommendation 1

(a) That AEMO investigate whether:

(i) the average period used for calculation of contribution factors could be aligned with the period over which the costs are incurred, preferably on a five minute basis

(ii) the ten business day notice period between publishing and applying contribution factors is appropriate or could be removed.

(b) That AEMO clarify how the causer pays procedure works and the specific variable that generator performance is measured against (i.e. frequency indicator or frequency) such that contribution factors can be calculated in real time by market participants.

Compliance with dispatch instructions

The AEMC understands that a perceived inconsistency between clause 4.9.8(a) and the requirements of schedule 5.2.5.11 of the NER has contributed to the actions by some generators which have resulted in the removal or detuning of the governor response that has traditionally provided primary frequency control during normal operation.

The AEMC does not consider that there is an inconsistency between clause 4.9.8(a) and the requirements of schedule 5.5.5.11 of the NER, for the reasons set out below.

Schedule 5.2.5.11 of the NER sets out the access standards for generators that must be met in order for them to gain access to the network. The minimum access standard in relation to frequency is that for a generating system under relatively stable input energy, active power transfer to the power system must not:

1) increase in response to a rise in system frequency

2) decrease more than two per cent per Hz in response to a fall in system frequency.

The access standard set out in schedule 5.2.5.11 is not an obligation that can be breached. Rather, a generator will not be granted access to the network if it is not capable of, at least, meeting the minimum access standard. On the other hand, a generator cannot be denied access to the network if it meets the relevant automatic access standard.

As part of the connection process, a generator may negotiate a different access standard to the automatic access standard with the relevant network service provider (and, if it is an AEMO advisory matter, with AEMO). Once the access standards have been agreed between the generator, the relevant network service provider and AEMO, they are included in the connection agreement and form part of the generator's performance standards.

Clause 5.2.5 of the NER states that a generator must plan and design its facilities, and ensure that they are operated to comply with its performance standards and its connection agreement. This clause is a civil penalty provision. Therefore, a generator will (at least) be expected to operate its system to respond as set out in (1) and (2) above.

As set out in Appendix E, a scheduled or semi-scheduled generator cannot change the frequency response mode of a scheduled generating unit without the prior approval of AEMO. Frequency response mode is defined in Chapter 10 of the NER 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."

Clause 4.9.4(a) states that:

> “a scheduled or semi-scheduled generator cannot send any energy out from a generating unit except:
>
> 1) in accordance with a dispatch instruction; ...; or
>
> 4) in the case of a scheduled generating unit:
>
> [...]
>
> (ii) as a consequence of operation of the generating unit's automatic frequency response mode to power system conditions.”

Therefore, the NER contemplates a generating unit automatically responding to frequency and being operated in such a way that it will not increase output in response to a rise in frequency or decrease in response to a fall in frequency.

In the AEMC's view, operating a plant in this way is not inconsistent with a generator's obligation to comply with a dispatch instruction.

Clause 4.9.8(a) of the NER is an absolute obligation in that a registered participant must comply with a dispatch instruction given to it by AEMO unless to do so would, in the registered participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment. This clause applies to all registered participants – that is, not just scheduled generators but scheduled loads and scheduled network service providers. This clause is a civil penalty provision to reflect the importance of compliance.

The AEMC's views on compliance with clause 4.9.8(a) of the NER were set out in detail in the final determination on Snowy Hydro's rule change request on *Compliance with dispatch instructions*. The Commission was clear in its determination that compliance with this clause is vital both for the maximisation of the NEM spot market and FCAS market outcomes, but also for system security. In the Federal Court decision in AER v Snowy Hydro Ltd,[134] the Federal Court stated that compliance with clause 4.9.8(a) is necessary to ensure that the power system remains secure.

The AER is responsible for monitoring compliance with the NER, including clause 4.9.8(a), and taking action where it deems necessary. To explain further its approach to monitoring compliance with the rules, the AER published a *Compliance and enforcement statement of approach*. This document sets out, amongst other things, the AER's objectives for enforcement and the factors and circumstances it takes into account in deciding to take any enforcement action.[135]

The reality of the physics of the system is that a generator is unlikely to ever hit its target precisely, and that the actions of its governor (if it is in frequency response mode) can pull a generator off its dispatch target. Fluctuations away from a participant's dispatch target in response to frequency deviations are likely to be minor, and can be distinguished from any deliberate action on the part of the registered participant. In these circumstances, the AER's *Compliance and enforcement statement of approach* would suggest that the AER is highly unlikely to take action against generators whose governors are responding in the way they are supposed to do in compliance with their performance standards.

5.3.2 Options for provision of primary regulating response

The current regulatory arrangements do not adequately incentivise the provision of primary regulating response to assist in frequency regulation during normal power system operation.[136]

The following sections discuss potential policy options that are likely to increase the level of primary frequency response that is active within the normal operating frequency band, between 49.85Hz and 50.15Hz. For the purpose of this discussion, this type of frequency response will be referred to as a **primary regulating response**.

134 AER v Snowy Hydro Ltd (No 2) [2015] FCA 58.

135 These factors include (amongst others): the nature and extent of the conduct that forms the breach; the impact of the conduct; whether the conduct was deliberate or avoidable had reasonable compliance practices been followed by the business; the extent of any financial gain; the business's own actions in relation to the conduct. In its Compliance and enforcement statement of approach the AER states that civil proceedings are more likely to be initiated when the conduct: resulted in significant detriment; demonstrated a blatant, ongoing or serious disregard for the law; is that of a person, business or sector that has a history of previous breaches.

136 The existing incentives for generators providing primary frequency response during normal operation are limited to the ability for helpful frequency response from a generating unit within a generation portfolio to offset harmful frequency response from within the portfolio as part of the determination of contribution factors under the causer pays procedure.

These options can be divided into two broad categories:

- Potential changes to existing arrangements to allow for or encourage the provision of a primary regulating response.
- Introduction of a new mechanism(s) to create an obligation or payments for the provision of a primary regulating response.

The Commission has identified two areas of potential change to existing arrangements that are likely to improve frequency performance during normal operation:

(a) The definition of the existing regulation services could be revised to require for primary regulating response to be provided along with the secondary response through the existing raise and lower regulation services

(b) The existing contingency services could be activated earlier by narrowing the trigger settings for some or all of the existing market ancillary services.

Potential new arrangements considered are:

(a) Arrangements for the provision of response only (not headroom):

  (i) Mandatory provision of response only

  (ii) Contract based procurement of response only

  (iii) Formation of new markets for the procurement of response only

(b) Arrangements for the provision of response and headroom:

  (i) Mandatory provision of response and headroom

  (ii) Contract based procurement of response and headroom

  (iii) Formation of new markets for the procurement of response and headroom

(c) Payment of incentives to generators (or loads) for active power response that helps to correct frequency deviations

The Commission considers that a number of the options identified above are not appropriate or viable for further consideration. These options are:

- option (a)(ii) contract based mechanism for the provision of response only
- option (b)(i) mandatory provision of response and headroom.

The specification and implementation of contract arrangements for the provision of a primary regulating response without headroom would require the service delivery to be specified, measured and verified. To do so is likely to be excessively complicated. For these reasons, the Commission has not considered this option in detail in this draft report.

The mandatory provision of response and headroom has not been considered in any detail either, due to the inherent inefficiency associated with setting a mandatory headroom requirement. Such a requirement is likely to incur substantial opportunity costs associated with maintaining headroom by withholding capacity from the energy market.

Summary of stakeholder submissions

The following section provides a summary of stakeholder submissions relating to the options presented for the provision of primary frequency control during normal operation.

Mandatory requirement

In response to the issues paper, a number of stakeholders supported a mandatory obligation for the purpose of delivering primary frequency control for frequency regulation including Pacific Hydro, TasNetworks and the Government of South Australia.[137]

S&C Electric suggested that primary frequency response should be uniformly provided from all connected and operational synchronous plant, and that a mandatory mechanism is likely to be the most appropriate mechanism to deliver such a uniform response.[138] S&C Electric also noted that the provision of such a response should be valued or remunerated.

TasNetworks' submission set out the following advantages that are delivered through the uniform mandatory provision of primary frequency response by all (or most) generators throughout the power system:[139]

- supports stable power flows throughout the transmission network that are likely to closely align with AEMO system modelling that is used to inform the application of network constraints on the energy dispatch process
- supports system resilience, which is understood as the ability for the power system to stabilise and recover following multiple contingency events
- provides for good frequency control and frequency performance which is a fundamental characteristic of operating an AC power system.

A large number of stakeholders expressed support for the development of market based options for the purpose of delivering the frequency services necessary to support

137 Submissions to issues paper: South Australian Department of the Premier and Cabinet, p. 2.; Pacific Hydro, pp. 8-11; TasNetworks, p. 5.

138 S&C Electric Company, submission to issues paper, p. 6.

139 TasNetworks, submission to issues paper, p. 5.

adequate frequency control as a preference to any mandatory mechanism.[140] Energy Australia's submission noted that:

> "where possible, primary frequency control services should be procured through a market mechanism. As primary frequency control comes at a cost to market participants, […] there should be incentives for participants to continue to provide that service. However, we acknowledge that where a well-functioning market cannot be established to procure the service, a mandatory requirement may be appropriate where the costs of establishing the response mechanism are not excessive."

A number of stakeholders noted that under a mandatory obligation to provide primary frequency response, those generators with the existing capability to be frequency responsive will face lower cost of compliance than others who do not have the capability.[141]

Energy Queensland noted in their submission that while a uniform mandatory obligation may appear technology neutral, the requirement for the control to exist at the generator may hinder the development of innovative solutions for the provision of such a service.[142]

Incentive payments

AGL indicated that consideration of a capacity reserve requirement for primary frequency response must include some financial benefit for the generator for the lost opportunity cost for electricity generation associated with the provision of such a reserve.[143]

The stakeholders indicated broad agreement that market participants who provide frequency response should not be penalised and should be rewarded for doing so.[144] In addition to supporting mandatory provision of primary frequency control, Pacific Hydro and S&C Electric indicated support for payments to incentivise the provision of primary frequency response.[145]

5.3.3 Assessment of options for the provision of primary regulating response

The options discussed in further detail in the following sections are:

(A) Provision of a primary response with regulating FCAS

---

140 Submissions to issues paper: AGL Energy, p. 3; Energy Australia, p. 5; Energy Queensland, pp. 7-8; Clean Energy Council pp. 1-2; Meridian Energy, pp. 6-7; Origin Energy, p. 1; Snowy Hydro, p. 7; Tesla, pp. 4-5.

141 Submissions to issues paper: AGL, p. 3; Australian Energy Council, p. 2.

142 Energy Queensland, submission to issues paper, p. 5.

143 AGL Energy, submission to issues paper, p. 4.

144 Submissions to issues paper: AGL Energy, p. 3; Energy Australia, p. 5.

145 Submissions to issues paper: Pacific Hydro, pp. 8-11; S&C Electric Company, p. 6.

(B) Activation of existing contingency FCAS at a narrower frequency setting

(C) The mandatory provision of response only (not headroom)

(D) The procurement of response and headroom via contracts

(E) Development of new markets for primary regulating response and headroom

(F) Introduction of incentive payments for primary regulating response through changes to causer pays.

The Commission has undertaken an assessment of each of the options presented in this section against the assessment principles identified for the review outlined in Chapter 4. An overview of the assessment of each option is included below following the description of the option.

A - Provision of a primary regulating response with regulating FCAS

Description of option

One option is to enable the provision of primary response as a component of the existing raise and lower regulating FCAS.[146]

Under such an arrangement, a generator that is enabled to provide the regulating raise service would provide the service either as a response to a change in locally measured frequency or in response to a signal from the AGC system. Appropriate control logic would be required to support the provision of both a primary and a secondary frequency response from a single generating unit. Example priorities of such a control logic were suggested in the Hydro Tasmania submission to the issues paper:[147]

"• Outside a narrow AGC operation band (yet to be defined), the frequency control has the highest control priority.

• Outside the AGC operation band AGC signals should be suspended.

• Once the frequency is back within the AGC operation band, the focus is on keeping the frequency within this band."

Such a control logic would prioritise primary response where a frequency deviation exceeds a predetermined "AGC operation band", such as 49.95Hz - 50.05Hz. Within this narrow band, response to AGC signals would be prioritised.

Under the current market framework, AEMO specifies the technical characteristics of each of the market ancillary services in the MASS and then procures those services in order to maintain a secure operating state and meet the power system security

146 A variation of this option was suggested by the Yokogawa representative to the ASTAG at the synchronous generators focus group meeting held on 11 October 2017.

147 Hydro Tasmania, submission to issues paper, pp. 7-8.

standards, i.e. the frequency operating standard.[148] Therefore, AEMO has some discretion to vary the specifications in the MASS and the quantities of each of the market ancillary services in order to maintain a secure operating state and meet the frequency operating standard.

The definitions of fast, slow, delayed and regulation services in the NER provide some guidance as to the performance characteristics of each of these services. These definitions go some way to defining the mechanism for triggering the change in generation or load that constitutes the service.

- The NER definitions for the fast and slow services include the words, "in response to the locally sensed frequency of the power system".[149]
- The NER definition for the delayed services includes the words, “in response to a change in the frequency of the power system beyond a threshold or in accordance with electronic signals from AEMO".[150]
- The NER definition for the regulation services includes the words, “in accordance with electronic signals from AEMO”.[151]

As per the NER definitions, the fast and slow services are intended only to be triggered in response to the local measurement of frequency. The regulation services may be triggered only in accordance with electronic signals from AEMO and the delayed services can be triggered by either of these mechanisms.

If this option was pursued, the Commission considers that, at a minimum, the NER definition of each of the regulation services would need to be amended to include the words, "or in response to the locally sensed frequency of the power system."[152] Such a change would allow for the specification of the regulation services in the MASS to include triggering in response to an electronic signal from AEMO or in response to locally measured frequency.

The Commission understands that not all providers of regulating FCAS may be capable of providing both primary and secondary response. The Commission is interested to hear from stakeholders on the likely impacts of this approach for providers and potential providers of regulation services.

Summary of assessment

Key points related to the Commission's assessment of the provision of primary response as a component of the existing regulation services are:

148 Clause 3.8.1 of the NER.

149 NER chapter 10 definitions: fast raise service, fast lower service, slow raise service, slow lower service.

150 NER chapter 10 definitions: delayed raise service, delayed lower service.

151 NER chapter 10 definitions: regulating raise service, regulating lower service.

152 This is one aspect of the NER that would likely need to change to implement such an approach. Further investigation will be required in order to determine the full suite of necessary changes.

- This option establishes a framework for AEMO to be able to procure primary frequency response from market participants via the existing markets for regulation services. This change is likely to lead to an improvement in the frequency performance in the NEM during normal operation.

- This option utilises the existing established market processes for regulating FCAS which provides for greater simplicity and transparency, and assists with the verification and assessment of the service.

- Under this option it may be difficult to differentiate between the range of equipment capabilities for active power control in response to frequency. As such, there may be some challenges in determining the performance criteria for the primary response component of the revised regulation services. In addition there are expected to be challenges associated with determining the method of prioritisation of local measurement versus response to AEMO signals, and the verification of the service provision.

- This option does not provide a natural incentive for a universal distribution of primary response throughout the power system. Any regional requirements for response would need to be dealt with via regional constraints, as is the case for existing FCAS.

- In combining two types of ancillary services, local (primary) response and response to AEMO electronic signals (secondary), this option reduces the flexibility of the existing frequency control arrangements. This reduction in flexibility may impact on the ability of market participants to meet the performance requirements of the revised regulation services. In addition, it would be difficult for AEMO to differentiate between the quantity of primary and secondary response active in the system at any time, if this was required.

- AEMO is well placed to coordinate the amount of primary regulating service and any constraints that may apply to its procurement. However, consistent with the existing arrangements for regulating FCAS, while AEMO is required to meet the frequency operating standard, it bears no financial risk for over- or under-procurement of the quantity of the service. Further, appropriate risk allocation is contingent on the effective application of the causer pays procedure for determining the allocation of costs associated with regulating FCAS.

B - Activation of existing contingency FCAS at a narrower frequency set point

Description of option

Under this option, the trigger points for some or all of the existing contingency services are narrowed.[153] The existing fast, slow and delayed market ancillary services are triggered in response to locally sensed frequency of the power system. Under the

153 NER clause 3.11.2 – Market Ancillary Services. The fast, slow and delayed services are commonly referred to as contingency services.

existing framework, these services provide a primary response to correct changes in system frequency outside the normal operating frequency band (49.85 Hz – 50.15 Hz). If some or all of these services were triggered at a narrower frequency setting, such as 49.95Hz to 50.05Hz this could provide the required primary response to help regulate system frequency during normal operation.[154]

The existing contingency services could be triggered earlier through changes to two different areas of the existing frequency control arrangements:

1. AEMO could independently change the settings in the market ancillary service specification (MASS).

   The NER require AEMO to develop a MASS that sets out:

   (a) a detailed description of each market ancillary service

   (b) the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant market ancillary service and also when a market participant provides the relevant kind of market ancillary service.

   If AEMO considered it appropriate, in order to meet the frequency operating standard, it may narrow the frequency trigger points for the fast, slow or delayed services, through a change to the MASS.

2. The Reliability Panel could amend the normal operating frequency band in the frequency operating standard to drive activation of the existing contingency services at a narrower frequency setpoint.

   The frequency operating standard is developed and published by the Reliability Panel.[155] Its purpose is to define the range of allowable frequencies for the power system under different conditions, including normal operation and following contingency events. AEMO is responsible for maintaining power system frequency in accordance with the requirements of the standard, which informs how AEMO operates the power system, including through applying constraints to the dispatch of generation or procuring FCAS.

154 It may be adequate for only the “fast” service to be triggered at a narrower frequency setting. Under the market ancillary service specification (MASS), the “fast” service is required to provide a frequency response within 6 seconds and then hand over to the slow service which provides a response within 60 seconds. In theory the fast service could be triggered earlier and provide a frequency regulation service during normal operation, handing over to the existing secondary regulation service. In the event of a contingency event, the fast service would trigger earlier then hand over to the slow service.

155 The Reliability Panel determines the frequency levels associated with each of the NER defined bands in the frequency operating standard, the time frames for the restoration of frequency back to within the various bands, and the percentage of time that frequency must stay within the normal operating frequency band and normal operating frequency excursion band.

Therefore the deterioration of frequency performance under normal operation could be addressed by setting a narrower allowable frequency distribution for AEMO to operate the power system to. This could be achieved by amending:

(a) the frequency *levels* that apply to each band in the frequency operating standard that relate to normal operation; or

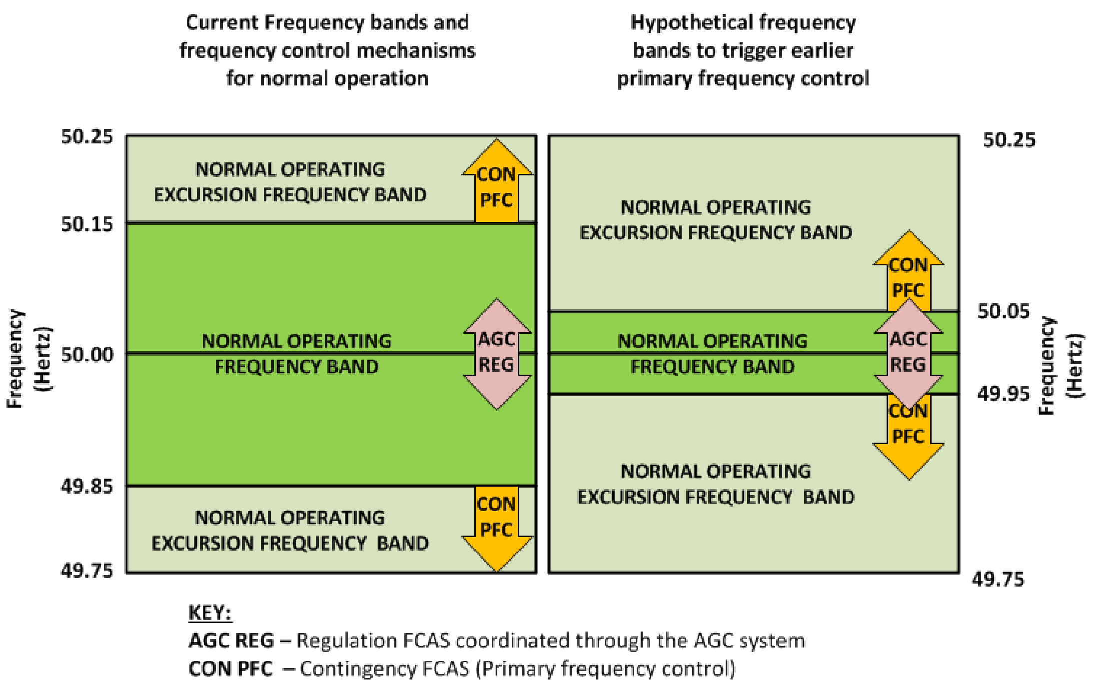
(b) the *structure* of the frequency operating standard by adding a new band that is narrower than the existing normal operating frequency band.

This section of the paper focuses on amendments to the frequency levels in the frequency operating standard. The option of adding a new band to the standard is discussed below as a component of option E, which discusses potential arrangements for the establishment of a new ancillary service market for a primary regulating service.

Contingency FCAS is dispatched through the FCAS markets and triggered in response to local frequency measurement in accordance with the individual frequency settings allocated by AEMO. The basis for these frequency settings is set out in the MASS, which is in turn written with reference to the frequency bands specified in the frequency operating standard.

Under this arrangement, regulating FCAS provides secondary frequency control via the AGC system within the normal operating frequency band, and primary frequency control is provided by contingency FCAS when the power system frequency deviates outside of 49.85 – 50.15Hz. This is shown on the left hand side of the Figure 5.4.

Figure 5.4 Hypothetical changes to the normal operating frequency band



In theory, the trigger point for primary frequency response provided by the contingency FCAS could be narrowed by tightening the normal operating frequency band. The right hand side of Figure 5.4 shows such an arrangement with a normal operation band set at 49.95 - 50.05Hz.

Under this option the question of whether the 99 per cent requirement in the frequency operating standard would continue to be appropriate would need to be assessed, as would the extent to which this statistical requirement may need to be changed to reflect the desired power system frequency distribution.[156]

Summary of assessment

Key points related to the Commission's assessment of the activation of the existing contingency services at a narrower frequency setpoint are set out below:

- While this option utilises the existing ancillary service markets, it represents a substantial change to the frequency control frameworks in the NEM and would require a review of the frequency operating standard and the MASS in order to be implemented.
- Under this option, AEMO has the flexibility to determine how much of each service it enables and dispatches to meet the requirements of the frequency operating standard.
- AEMO is well placed to coordinate the amount of primary regulating service and any constraints that may apply to its procurement. However, consistent with the existing arrangements for contingency FCAS, while AEMO is required to meet the frequency operating standard it bears no financial risk for over- or under-procurement of the quantity of the service. Further, appropriate risk allocation is contingent on the existing cost recovery arrangements for contingency FCAS services, which broadly apply costs across generators and market customers.
- This option does not provide a natural incentive for a universal distribution of primary response throughout the power system. Any regional requirements for response would need to be dealt with via regional constraints, as is the case for existing FCAS.
- There is an increased likelihood that less than the full quantity of contingency response is available in the event of a large credible contingency event. This could possibly be addressed through a re-assessment of required FCAS volumes.

156 The frequency operating standard includes a requirement that, in the absence of any contingency event the frequency shall be contained within the normal operating frequency band(49.85Hz - 50.15Hz) for 99 per cent of the time except for brief excursions within the normal operating frequency excursion band(49.75Hz - 50.25Hz). Excluding contingency events, the total time outside the normal operating frequency band in a 30 day period must be less than 1 per cent. In effect, there is a requirement that the frequency be maintained within the normal operating frequency excursion band for 100 per cent of the time and 99 per cent of the time within the normal operating frequency band.

Where a contingency service is utilised to provide primary frequency regulation there is a chance that the active power response capacity may not be fully available when required to respond to a contingency event. If the quantity of contingency services was not increased to counteract this effect, such a scenario could lead to an improvement in frequency regulation at the expense of an increase in the risk exposure to contingency events. Therefore, the quantity of contingency FCAS may need to be increased to account for the utilisation of available capacity for frequency regulation.

C - The mandatory provision of response only (not headroom)

Description of option

Improved frequency performance could be delivered by the establishment of a new mechanism to require or procure the provision of primary frequency response for the purpose of frequency regulation during normal operation. This response could be provided independently of any allocation of headroom capacity.

A mandatory arrangement for the provision of the primary regulating response could be designed with or without the inclusion of a requirement for maintaining a specific headroom capacity. For example, the requirement may state that the response must be provided only by generators that are capable of providing the response, in terms of the technical capability of the generator and the available operating capacity. This option implies that the generating unit is to be operated in a frequency responsive mode, but is not required to withhold capacity from the energy market in order to provide the response.[157]

A similar arrangement has recently been implemented by the United States Federal Energy Regulatory Commission (FERC) which require all new large and small generation facilities to install, maintain and operate equipment capable of providing primary frequency response as a condition of connection.[158] This rule requires generators to be responsive to changes in system frequency but does not require generators to maintain headroom capacity.

The Commission considers that where a primary regulating response is required to be universally provided, in the absence of any requirement for headroom capacity, a mandatory obligation may be an effective mechanism for the delivery of such a response. The design of a mandatory obligation to provide primary regulating response would need to address the specification of the required response and which market participants the requirement would apply to, including whether the requirement would apply to existing generators as well as new generators. Such an

157 The Commission understands that when a thermal generator operates in frequency response mode, the maximum output of the generator may be reduced due to the throttling action of valves feeding steam to the turbines.

158 FERC, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response - Final Rule, 15 February 2018..

obligation may apply to scheduled and semi-scheduled generators (over 30MW) or also to scheduled loads and potentially registered generators (over 5MW).

Such an obligation may be incorporated into the generator technical performance standards that apply for generator connection to the network, or via alternative mechanisms within the NER (such as direct obligations to provide the service).

The Commission notes that while it is clear that a new mandatory obligation can be applied to new generator connections, the issue is less clear when considering whether a mandatory obligation could be implemented by way of changes to generator minimum access standards to all new and existing generator connections.[159]

If an amendment to the minimum access standards to require the mandatory and unpaid provision of a primary regulating service could not be applied to parties who have their access standards reflected in existing connection agreements at the time the rule comes into effect universal provision of a mandatory primary regulating service may not be possible to achieve immediately. It may take some time for existing generators/loads to retire (or seek to vary their connection agreements), and for new ones (subject to the new rule) to take their place.

This has important implications for the consideration of a mandatory approach to the provision of a primary regulating service, particularly if the intention is to achieve an immediate, wide geographical distribution of service provision.

A mandatory obligation for primary frequency response may be designed specifically to provide improved system resilience following multiple contingency events. For example a mandatory response obligation may be set such that generators are required to provide an active power response outside of some wider frequency band, say the operational frequency tolerance band (49.0 Hz – 51.0Hz). While such a response would not provide any assistance for the regulation of frequency during normal operating conditions, it would increase the likelihood that the system would recover from some potential multiple contingency events. The Commission considers that the costs to generators of such a requirement may be low as such a response would be rarely called upon, and in the event that it were activated, the system support provided would be likely to offset load shedding that would otherwise be needed to stabilise the power system following such extreme events.

The Commission recognises that generators who are required to provide primary frequency response during normal operation are likely to incur operational costs associated with providing the primary regulating response. These operational costs are understood to include potential reductions in operational efficiency from requiring the generator to be frequency responsive. Varying output increases fuel consumption and may have maintenance impacts from working the generator harder as it follows frequency variations.

159 AEMC, Generator technical performance standards - consultation paper, 19 September 2017, pp. 46-47.

Summary of assessment

Key points related to the Commission's assessment of the mandatory provision of primary response are set out below:

- If a mandatory requirement for primary frequency response were universally applied to a large proportion of the generation fleet, it is likely to lead to a strong improvement in frequency performance during normal operation. This option would also support system resilience by providing a wide geographical distribution of frequency response capability.
- There may be some challenges in specifying the performance criteria for the mandatory response. Some generators would be able to meet the requirements at lower cost than others.
- While relatively straight forward to apply to new connecting generators, there are issues with implementing this option through a change to minimum access standards for existing generators.
- Generators bear the risk of providing the required frequency response. While a universal requirement may mean that the costs on each generator are relatively low, those generators that provide the response would not necessarily be the generators that can do so at lowest cost.
- This option may involve the specification of a minimum performance requirement for all generators to meet, which would not support innovative approaches to improve frequency response capability.

D - Contract procurement of primary regulating response and headroom

Description of option

One alternative mechanism for the provision of primary regulating response is via a contract procurement model. Under such a model, AEMO would specify the performance characteristics and quantity of primary frequency response and these criteria would be incorporated into a contract for services that may be made between the service provider and AEMO or potentially a TNSP.

Contracts could be established via a competitive tender process or bilaterally negotiated process. The Commission will consider whether such a contracting process should be set out in the NER, as is the case for system restart ancillary services and network support ancillary services.

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

The form and characteristics of such contracts would need to be carefully considered. The details of the provision of the service would need to be outlined in the contract, i.e. what are the availability and capacity obligations for the provider over the term, how will the service be dispatched and what other operational protocols need to be considered. Payments could be structured either as a fixed charge, a capacity payment, a usage payment, or some combination of the above.

If an emerging power system need is identified, a contracting approach may be attractive (at least as an interim arrangement) in order to enable AEMO to be able to procure primary regulating response as required. Following a rule change to establish powers for AEMO to negotiate and establish contracts for a primary regulating service, AEMO could set up bespoke contracts with capable generators for the provision of this response. Such arrangements are likely to have a shorter implementation time frame than the establishment of new ancillary service markets and as such may be viewed as a potential interim measure pending the activation of new market arrangements.

Summary of assessment

Key points related to the Commission's assessment of the contract procurement of primary response and headroom are set out below:

- A contracting arrangement would enable AEMO to specify the procurement of additional primary regulating services to assist with frequency regulation in order to meet the frequency operating standard.
- Contract procurement may provide revenue certainty to encourage investment in frequency response capability. However, such certainty will come through long term contracts which in turn may act to reduce the flexibility of these arrangements.
- Could allow for a broad geographical distribution of frequency response depending on the specifications of the contracting process.
- AEMO may face limited incentives to minimise the costs of contracts, which would be passed through to consumers.

E - Development of new markets for primary regulating response and headroom

Description of option

The provision of primary regulating response could be incentivised through the formation of new markets for frequency control services.

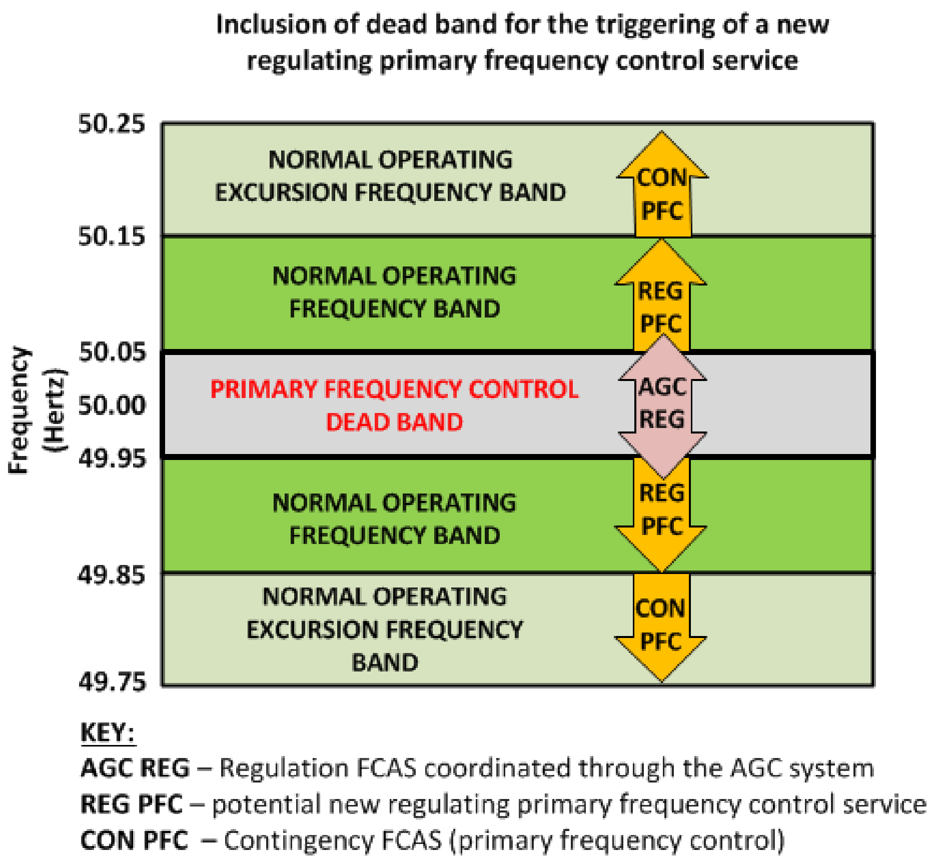
Setting up separate markets for raise and lower primary regulating services would allow AEMO to prescribe the required amount of each type of FCAS dynamically in response to changing power system conditions and for these services to be co-optimised through the NEM dispatch engine (NEMDE), as is the case for the existing regulation and contingency services.

This change would also impact the determination of causer pays contribution factors, which would need to be further considered.

The Commission considers that the creation of a new primary regulation service could involve amending the structure of the frequency operating standard to set out a new band for triggering the service. The specification of a new band in the frequency operating standard is likely to increase the precision of the frequency performance requirement set out in the frequency operating standard.

Figure 5.5 shows how these potential new primary regulating services may operate in relation to the existing frequency bands and frequency control services. In this example, the primary regulating service operates outside of a dead band that is shown notionally at ± 0.05Hz.

Figure 5.5 Hypothetical frequency band for primary regulating service



The AEMC could (following receipt of a rule change request) establish the framework for this new ancillary service in the NER. During the rule change process, the Commission would need to consider whether it is most appropriate for the trigger setting or dead band for these services to be specified in the MASS, the frequency operating standard or in the NER and the implication of each of these options.

The frequency operating standard could be amended by the Reliability Panel following a change to the NER to add a new band that sits within the normal operating frequency band. This band could then be used to establish new FCAS markets for the provision of a primary regulating service (i.e. raise and lower).

In order to complete the implementation of this new service AEMO would also need to amend the market ancillary services specification to set out a detailed description of the new services and their performance parameters and requirements.

The trigger point for this new service could sit within the NER, the MASS, or it could refer to a setting in the frequency operating standard. If it were intended that the trigger point for this new service should be set in the frequency operating standard then it would also be necessary for the Reliability Panel to review and revise the frequency operating standard to create this new band.

Summary of assessment

Key points related to the Commission's assessment of the establishment of new ancillary service markets for primary response and headroom are set out below:

- The creation of a new raise and lower primary regulating services would allow AEMO to set the quantity of primary frequency response required to meet the requirement of the new frequency operating standard.
- A new market would likely to be a flexible and adaptive mechanism into the future. By creating a stand-alone primary regulating service, AEMO could specify the performance characteristics independently of the other market ancillary services.
- A new market would have the benefit of fitting in with the existing market based sourcing structure for frequency control services that are provided in parallel (and co-optimised) with the wholesale energy market.
- There may be significant time, cost and complexity associated with the development and operation of a new market. In order for a new market to be effective, it would need the active participation of a sufficient number of participants to ensure trading liquidity and competitive (efficient) bidding.
- AEMO is well placed to coordinate the amount of primary regulating service and any constraints that may apply to its procurement. However, consistent with the existing arrangements for regulating FCAS, AEMO bears no financial risk for over- or under-procurement of the quantity of the service. Further, appropriate risk allocation would be contingent on the effective application of a causer pays procedure for determining the allocation of costs associated with the new service.
- This option does not provide a natural incentive for a universal distribution of primary response throughout the power system. Any regional requirements for response would need to be dealt with via regional constraints, as is the case for existing FCAS.

F - Introduction of incentive payments for primary regulating response through changes to causer pays

Description of option

Incentives for the provision of a primary regulating response could be established through changes to the existing causer pays arrangements.

One potential option for increasing the provision of primary frequency regulation services is to offer a financial incentive. Appropriately structured incentives can be an effective strategy to support the voluntary provision of valuable services within the NEM.

Currently there are no direct incentives for market participants to provide primary frequency regulation services in the NEM.[160] Under the current arrangement only secondary frequency (AGC based) regulating services are remunerated within the normal operating frequency band.

Economic value range for incentives

Conceptually, there is a normal pricing envelope that any incentive should sit within. At the lower bound, in order for such an incentive to be effective it must, at a minimum, fully compensate service providers for the marginal costs incurred in providing the service. To the extent that no headroom is required to be maintained, the marginal costs will be associated with ensuring the technical capability to be frequency responsive is available and enabled along with any additional operating costs such as incremental maintenance costs and additional fuel costs associated with any reduction in operating efficiency.

Similarly, in order for the incentive to be consistent with the NEO, the payment should not exceed the value of any benefits accruing from the provision of the service. The benefits are related to the value to consumers of any improvements in the reliability and security of supply of electricity. If the value of the service is below the marginal cost, then there is no economic basis for an incentive arrangement.

These criteria provide a starting point for assessing potential incentive arrangements.

Approach to providing incentives

Where marginal costs are very low, and where no other disincentives apply, the absence of a positive incentive may not undermine the ongoing provision of primary frequency regulation services where they are already being provided. However, in the absence of a positive incentive, market participants are unlikely to commence providing such a service where they currently do not.

---

160 The existing causer pays procedure provides a limited incentive for the provision of primary frequency response during normal operation. The incentive is limited to rewarding helpful generation response from a generating unit within a generation portfolio as an offset to operation that contributes to frequency deviations from other generating units within the portfolio.

Where the benefit of the primary frequency regulation service is sufficiently high, it may be reasonable to offer an incentive payment above the marginal cost of providing the service. Such an incentive could be provided a number of ways, for example, through the development of new primary frequency regulation markets (raise and lower) alongside the existing eight FCAS markets, or through changes to existing frameworks such as causer pays arrangements.

Use of the causer pays process to incentivise primary frequency regulation

Use of existing frameworks such as the causer pays arrangements has the benefit of ease of implementation (both in terms of time and cost), and flexibility to trial an option with the potential to subsequently move to an alternative arrangement such as development of a market should this appear desirable in the future.

Under the current AEMO causer pays procedure, contribution factors are intended to represent the extent to which a market participant has contributed to a frequency deviation (i.e. whether a market participant's deviation from dispatch instructions has contributed to frequency deviating from 50Hz). The individual market participant factors are averaged across portfolios and where a contribution factor is assessed to be greater than zero, i.e. has a net positive impact (improvement) on frequency control, it is set to zero. The initially preferred framework for providing incentives for market participants to provide primary frequency regulation services is to allow for positive contribution factors to be rewarded. This could be based on an identical proportional response to the value of negative contribution factors or some other proportional payment. As is the case under the existing causer pays procedure, providers of regulating FCAS would need to be excluded from calculations for the periods they are so enabled, in order to avoid the potential for double payment. Adopting this approach would have a number of implications:

- The cost of these incentive payments will add to the overall pool of costs associated with frequency regulation. As a result, the overall costs associated with paying for frequency regulation are likely to increase, at least in the short term. This effect may moderate in time due to potential reductions in the requirement for regulating FCAS, however it is understood that regulating FCAS will continue to be required into the future and is not likely to reduce to zero

- Based on a equal valuation of negative and positive contribution factors, the residual charge paid by market customers is likely to increase as the total costs associated frequency regulation increase.[161]

A benefit of this arrangement is that no additional data would be required and the only procedural change would be to no longer constrain the value of contribution factors to a maximum value of zero.

161 This effect may be mitigated if negative contribution factors were valued higher than positive contribution factors, which would shift the allocation of regulation costs towards those with negative contribution factors.

This would also serve to reduce the current distortionary arrangement whereby, in effect, positive contribution factors are valued to the extent that they occur within a portfolio where they can be offset against generating units with negative contribution factors. This contrasts with a market participant that does not have units with negative factors and therefore cannot gain any benefit from a positive contribution factor.

Under this proposed causer pays arrangement, only scheduled market generators and loads would be incentivised to actively manage their exposure to risks associated with contributing to frequency deviations. As with the existing causer pays arrangements, any costs of frequency regulation that are not attributable to a market generator or load would be recovered from market customers in proportion to their energy demand.[162] Further developments may consider the extension of this responsibility to include market customers in the calculation of contribution factors. An example of such an arrangement is the deviation pricing model discussed in Chapter 8.

Summary of assessment

Key points related to the Commission's assessment of the changes to the causer pays arrangements to introduce incentive payments for primary frequency response are set out below:

- The introduction of incentive payments to the causer pays arrangements creates a balance between penalties and rewards for the behaviour of eligible market participants based on whether they contribute to frequency deviations or respond to correct such deviations.
- This arrangement may remove the need for a central procurer of primary regulating response, as market participants are incentivised to provide active power response that corrects any frequency deviations. This avoids the potential inefficiencies associated with modelling the 'ideal' volume of services needed to maintain good frequency control.
- This mechanism relies on the accurate measurement of the frequency response of market participants. Further work is required to determine the capabilities and limitations of the existing four second causer pays contribution factor data and whether it is appropriate to use this data as the basis for the allocation of incentive payments.
- This approach is likely to be highly flexible and adaptive to changes in the power system as they happen and is likely to encourage innovative technical and financial arrangements to support frequency control.
- This decentralised approach may allow for generators to develop innovative predictive tools to take advantage of times where frequency performance is likely to be poor and therefore frequency response more valuable.

162 AEMO, causer pays procedure consultation – Issues paper, December 2016.

- As there is no central procurement of primary frequency response, there is likely to be less certainty as to the amount of response active at any point in time and how the system would be expected to behave in the event of a contingency event.

  Reporting of generator settings and the performance of the power system in general may assist with transparency in this regard.

- While this incentive arrangement would be open to all market participants, there may be geographical variations in the effectiveness of the incentive, as a result the mechanism may or may not drive a broad geographical distribution of response.

- This mechanism is likely to be relatively simple and low cost to implement, possibly only requiring a rule change in relation to the goal of the contribution factor procedure to allow valuation of positive factors, followed by subsequent changes to AEMO's causer pays procedure.

Conclusions on the provision of primary regulating response

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

However, the Commission recognises that the opportunity costs associated with the provision of response and headroom are likely to be substantial and it is appropriate that providers of the service be remunerated for these costs. Under a mandatory obligation, those generators that provide the response would not necessarily be the generators that can do so at lowest cost.

While relatively straightforward to apply to new connecting generators, there are issues with amending access standards in the NER in relation to generators with existing connection agreements based on existing and historical access standards. A key design component of a mandatory response requirement relates to the specification of the necessary response, which may be technically challenging and difficult to achieve in a technology neutral way.

The Commission considers that appropriately structured incentives would be a more effective means of supporting the provision of a primary regulating response, and that an incentive framework that aligns with existing market structures would be more likely to minimise the costs of implementation.

Of the options considered, option F - the introduction of an incentive payments system for primary frequency regulation through the causer pays arrangements, and option A - the incorporation of a primary response into the delivery of regulating FCAS, appear to be the two options with the lowest cost approach.

The option of incorporating a primary response into the delivery of regulating FCAS would utilise the existing ancillary service markets for regulating raise and lower services to manage the frequency such that it remains close to 50Hz under normal operating conditions. While aligning with existing market frameworks, this option has some drawbacks in that only those market participants capable of providing a regulating response through AGC would be able to participate in the provision of a primary regulating service. Further, the establishment of these arrangements may require the specification of the type of regulating response that would be required, which may be difficult to undertake in a technology neutral manner.

The introduction of incentive payments to the causer pays arrangements creates a balanced price structure that penalises or rewards the behaviour of eligible market participants based on whether they contribute to frequency deviations or respond to correct such deviations. This approach is likely to be highly flexible and adaptive to changes in the power system as they happen and is likely to encourage innovative technical and financial arrangements to support frequency control. Reporting under this approach would likely be required in order to increase transparency around the levels of frequency response that are active in the system.

In relation to the balance of the options, the Commission recognises that changes to the frequency operating standard to allow for a narrower activation of contingency services as set out in option B is a relatively firm and blunt instrument for the purpose of improving frequency performance in the NEM.

Further, amending the levels in the existing frequency operating standard or the MASS to use contingency services for the management of frequency within the normal operating band represents a substantial shift in the approach to frequency management in the NEM. While such changes may be warranted in the long term, at this stage it is not clear that the benefits of such a change exceed the associated costs.

The introduction of a new primary regulating service through the establishment of a new market, option E, could be an effective approach. However, the Commission considers that such an approach is likely to be contingent on the ease of implementation, which would likely require a rule change request, changes to the frequency operating standard, changes to the MASS and potential consequential changes to the existing FCAS markets.

A contract market for primary regulating service, option D, may provide an interim solution if certainty over the quantity of response is required and this quantity is relatively stable over time. A contract market may however be less transparent and less flexible than a real-time market.

Draft recommendation 2

That the providers of a primary regulating response should be remunerated for the costs of providing the service, in particular where the opportunity costs of maintaining the capacity to provide the service (e.g. maintaining headroom to be able to increase output) are likely to be high.

The implementation of one of the following two options is likely to build on the existing market frameworks and support improved frequency control during normal operation:

- provision of a primary regulating response through the existing regulating FCAS markets
- changes to the causer pays arrangements to facilitate the provision of incentive payments for primary frequency response during normal operation.

Further work is required to investigate and describe the potential arrangements for the implementation of these options, and the associated costs and benefits of these arrangements.

6 Frequency monitoring, reporting and forecasting arrangements

This chapter sets out other areas where improvements could be made to market and regulatory arrangements that relate to frequency performance in the NEM. Specifically:

- section 6.1 describes the current and historical practice of frequency monitoring and reporting in the NEM, and the potential to improve the level of transparency around frequency performance
- section 6.2 provides a summary of the interactions between supply/demand forecasting and frequency control, along with a summary of the Commission's findings in this area as a result of the *Reliability frameworks review*.

The Commission considers that changes in these areas are likely to provide benefits in the current market environment.

6.1 Frequency monitoring and reporting

This section describes the current and historical practice of frequency monitoring and reporting in the NEM and the potential to improve the level of transparency around frequency performance through clear obligations for frequency monitoring and reporting.

6.1.1 The issue

The frequency monitoring and reporting requirements set out in the NER are primarily related to individual events. AEMO is required to report on frequency in relation to "reviewable operating incidents", which include events where the frequency of the power system is outside limits specified in the power system security standards.[163] The NER do not contain a requirement for AEMO to report regularly on power system frequency performance during normal operation.

Currently, AEMO produces frequency monitoring reports voluntarily on a periodic basis, with the most recent reports being published in December 2016 and August 2017.[164] These reports provide a summary of emerging trends in power system frequency performance in the NEM over a three year period. Specifically, they include:

- monthly averages for the percentage of time that the power system frequency is within the normal operating frequency band over a 30-day period for the mainland NEM and Tasmania

163 See clause 4.8.15(iii) of the NER.

164 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability%20/Ancillary-services/Frequency-and-time-error-monitoring

- the number of exceedance events on a monthly basis for each of the bands in the frequency operating standard.

In addition to the recent reports discussed above, the AEMO website contains an archive of frequency and time error monitoring reports published prior to 2016. This archive includes monthly frequency and time error monitoring reports from January 2011 through to June 2013. Quarterly frequency and time error monitoring reports were published by AEMO for Q3 2013 through to Q3 2014.

Prior to the formation of AEMO on 1 July 2009, NEMMCO published frequency monitoring and time deviation reports.[165] These reports were published monthly by NEMMCO from January 2004 through to January 2008.[166]

6.1.2 Stakeholder views

Submissions on the issues paper

The issues paper sought stakeholder views on whether there are any benefits to market participants of more regular reporting of frequency performance in the NEM.

Most stakeholders expressed strong support for AEMO being required to report more regularly on power system frequency performance.[167] Stakeholders indicated that the benefits of reporting would (depending on the specific reporting requirements) include:[168]

- giving generators a better understanding of how often and by how much the frequency is deviating
- alerting the market to the need for FCAS services and providing trend information that will assist potential investors with the timing of their investments
- helping to monitor the effect of any changes made to improve frequency response
- allowing (if the reporting includes participant-specific data) each participant to identify the periods where they are not meeting their dispatch targets, and

165 NEMMCO was the market operator from the commencement of the NEM up until the time that AEMO was formed in July 2009.

166 See: https://web.archive.org/web/20080503092944/http://www.nemmco.com.au:80/powersystemops/powersystemops.htm Archive dates: 10 September 2004 through to 3 May 2008.

167 Submissions to issues paper: AGL, p. 4; EnergyAustralia, pp. 5-6; Energy Networks Australia, p. 8; Energy Queensland, p. 8; Hydro Tasmania, p. 9; Meridian Energy, p. 7; Pacific Hydro, p. 11; Snowy Hydro, p. 10; S&C Electric Company, p. 8; TasNetworks, p. 9.

168 Submissions to issues paper: AGL, p. 4; Energy Queensland, p. 8; Meridian Energy , p. 7; S&C Electric Company, p. 8.

providing participants with the opportunity to interrogate AEMO's causer pays data and calculations

- understanding how much was spent on maintaining frequency within the normal operating frequency band (e.g. FCAS costs) and if standards were met or not met.

Several stakeholders considered that the costs of such a requirement would be negligible and would be outweighed by its potential benefits.[169] Snowy Hydro submitted that any monitoring and reporting conducted by AEMO should not be onerous on generators, who already undertake a significant amount of reporting.[170]

The issues paper sought stakeholder views on what frequency metrics would be most valuable for AEMO to report on. Submissions proposed the following metrics:[171]

- statistical analysis (histogram) of frequency
- time error trends
- number of excursions outside of the normal operating frequency band
- an assessment of how well frequency was maintained within the normal operating frequency band
- whether the frequency operating standard was met/not met
- fast Fourier transform analysis[172] to identify periods of oscillatory behaviour and assess the impact of any changes to frequency control arrangements
- frequency distribution during high, low or variable wind conditions
- average frequency by trading interval, disaggregated into work days and non-work days
- a regional breakdown of data, if there are significant differences between regions
- area control error-based reporting[173]

---

169 Submissions to issues paper: Meridian Energy, p. 7; Pacific Hydro, p. 11.

170 Snowy Hydro, submission to issues paper, p. 10.

171 Submissions to issues paper: EnergyAustralia, pp. 5-6; Hydro Tasmania, p. 9; Meridian Energy, p. 7; S&C Electric Company, p. 8; TasNetworks, p. 9.

172 Fast Fourier transform analysis enables the identification of different frequency components over a specific time window. Each component is a repetitive wave at different frequencies (number of repetitions), amplitude (height) and phase. These frequency components create a "signature" that can be used to identify particular events or behaviours, e.g. changes to AGC settings.

173 Area control error (ACE) refers to the shift of the area's generation (region connected by an interconnector) required to restore frequency and net interchange to their desired values. AEMO under its causer pays datasets for the recovery of regulating FCAS costs, reports ACE related metrics every 4 seconds.

- number of incidents where generator output is in phase with frequency
- for each participant, the periods where that participant did not meet their target and contributed to the frequency deviating outside of the normal operating frequency band
- cost of inertia and frequency control services
- available FCAS versus dispatched FCAS, for each category of FCAS.

Some stakeholders commented on the appropriate regularity of such reporting. S&C Electric Company proposed monthly reporting.[174] TasNetworks suggested quarterly reporting, unless AEMO is able to automate analysis and documentation to produce monthly reports without excessive effort.[175]

Technical working group meeting

At the AEMC's technical working group meeting on 17 January 2018, similar views were expressed about the potential benefits of more regular frequency reporting by AEMO.

Stakeholders noted that AEMO used to publish monthly reports on frequency soon after the relevant month, and suggested that there may be benefit in AEMO returning to this practice. Stakeholders discussed how relatively new participants to the market have limited access to information about frequency performance, and may benefit from more transparency around the rate of change of frequency (RoCoF) and frequency nadirs.

AEMO indicated that it was taking stakeholder views on frequency monitoring and reporting seriously, and that it would soon set out its proposed approach to addressing these concerns.

6.1.3 Analysis and proposed solution

The Commission considers that the frequency control framework in the NEM should promote transparency so that market participants are informed about issues that affect system security, and can make efficient investment and operational decisions.

Reporting on frequency performance

As noted in section 6.1.1, there is an existing provision in the NER that requires AEMO to report on events where the frequency of the power system is outside limits specified in the power system security standards.[176] However, the Commission is of the view

174 S&C Electric Company, submission to issues paper, p. 8.

175 TasNetworks, submission to issues paper, p. 9.

176 See clause 4.8.15(iii) of the NER.

that there are benefits of having greater transparency of the NEM's general frequency performance.

The Commission agrees with the benefits of frequency monitoring and reporting as described by stakeholders. Reporting on frequency outcomes provides a transparent means by which all affected parties can understand the frequency performance of the system. Regular monitoring and reporting should also support an understanding of the impact of any changes to existing mechanisms, or the introduction of new mechanisms, to improve frequency control performance.

The Commission is aware that AEMO is working through ways to address the lack of transparency around frequency performance, which may include a commitment to publish more regular reports. Even so, the Commission considers that a clear regulatory requirement for AEMO to monitor and report on frequency performance will help to achieve the outcomes set out above. Such a requirement would likely need to be given effect through the NER, as is the case with other AEMO monitoring and reporting obligations.[177]

Potential criteria for inclusion in frequency monitoring reports include:

- the number of exceedance events outside each of the bands in the frequency operating standard and the distribution of the time taken to return the frequency to the normal operating frequency band
- a measure of the distribution of the system frequency over the period, either through a statistical score such as standard deviation or graphically
- a measure of the behaviour of the power system in relation to rate of change of frequency and frequency stability
- a description of investigations into periods of oscillatory behaviour and the status of any remedial actions.

Reporting on FCAS market outcomes

Under the NER, the AER must monitor and report on significant variations between forecast and actual prices in the wholesale electricity market.[178] This obligation includes reporting on incidents when the spot price exceeded $5,000/MWh, known as

177 Examples of AEMO reporting obligations under the NER include: reporting on the operation of the lack of reserve framework under clause 4.8.4B; reporting on costs associated with non-market ancillary services under clause 3.11.10 for system restart ancillary services and 3.13.5 (b) & (c) for network support and control ancillary services; and reporting on the activation of the reliability and reserve trader mechanism under clause 3.20.6.

178 Clause 3.13.7 of the NER.

high price events. The AER reports on high price events that occur in the FCAS markets.[179]

The Commission considers that there may be benefits of more accessible information about the performance of FCAS markets. The Commission is interested to hear from stakeholders on the potential benefits of extending the obligation to monitor and report on frequency performance to include information on the performance of FCAS markets. The AER may be the appropriate party to prepare such market performance reports, in line with its existing reporting obligations.

AEMO's website holds data about FCAS prices and providers, but this information is not collated and published in a way that is accessible to all stakeholders. A requirement to do so may help to identify trends about the number of providers in each of the FCAS markets, the total enablement costs and the amount of each service that is actually required. This is similar to the approach taken by UK's National Grid in its monthly balancing services summary.[180]

Discussion of frequency monitoring and reporting

The design of new requirements for the reporting on frequency performance by AEMO and FCAS market outcomes by the AER would need to consider the following issues:

- *The coverage and granularity of reporting:* The reporting of frequency performance by AEMO could cover the impact of individual participants or be undertaken on a regional basis. In relation to reporting on FCAS market performance it would likely be much more complex for the AER to report on every NEM participant, therefore it may be more practical that FCAS market performance reports be prepared by the AER on a regional basis.

- *Access to data:* The content of the reporting may depend on the extent to which AEMO and the AER have access to the data required to fulfil the obligation. The AER may need to seek input from AEMO and other market participants.

- *Regularity of reporting:* It will be important to recommend the most appropriate balance between the regularity of the reporting and the metrics required to be reported on so as not to impose an inefficient administrative burden on AEMO and the AER. One option would be a requirement for the publication of monthly reports on key metrics with a longer report on system and market trends published annually.

- *Monitoring of the success of changes to the frequency control arrangements:* The Commission considers that regular reporting of frequency performance will

179 For example, the report into high price events in South Australia on 13 and 14 October 2017: AER, Report into market ancillary service prices above $5000/MW - South Australia, 13 & 14 October 2017, 12 January 2018.

180 See: https://www.nationalgrid.com/sites/default/files/documents/34101-MBSS_MAY_2014.pdf. These reports contain information on how much of each balancing service was procured, the total cost, and a comparison against previous months and years.

provide the additional benefit of enabling the monitoring of the relative success of any changes to the frequency control arrangements, such as those considered in Chapter 5. The availability of regular frequency monitoring reports will also assist in the timing of any future changes to the frequency control arrangements, such as those discussed in Chapter 8.

- *Whether the obligation should be set out in the NER or in procedures:* The requirements relating to the FCAS market reporting obligation may be set out in the NER or in procedures. Is it more appropriate for the NER to set out in detail what AEMO and the AER are required to monitor and report on, and in what format, or should the relevant market body have some discretion in this regard? Setting out detailed requirements in the NER would result in greater certainty and control over how the AER and AEMO fulfil their reporting obligations. However, it would mean that any changes to the specifics of that obligation would need to be done through a rule change process, which may be more complex or lengthy than if the AER and AEMO had discretion to make changes through adjustments to procedures.

Draft recommendation 3

That a rule change request be submitted to amend the NER to require:

(a) AEMO to monitor, and publish reports on, frequency outcomes with respect to the requirements of the frequency operating standard

(b) AEMO to provide information to the AER on the performance of FCAS markets and for the AER to monitor, and report on, the performance of FCAS markets.

6.2 AEMO's supply/demand forecasting arrangements

This section describes the linkage between supply/demand forecasting and frequency control along with an explanation of the work being completed on forecasting by the Commission through the *Reliability frameworks review*.

6.2.1 The issue

As discussed in section 3.2, changing technology and behaviour in the power system is leading to increased variability and unpredictability of supply and demand.[181] This variability of supply and demand makes good frequency performance more difficult to achieve as the frequency varies whenever the supply from generation does not precisely match customer demand. The variability may also raise wider security and/or reliability concerns in the market beyond the dispatch time frames. Such issues

181 The system frequency will rise whenever total generation is higher than total energy consumption, and vice versa.

are beyond the scope of this review, but are being considered elsewhere e.g. through the AEMC's *Reliability frameworks review*.

To balance supply and demand, AEMO dispatches scheduled generation to meet its forecast demand. Section 4.1.1 of the interim report for the *Reliability frameworks review* provides a description of AEMO's central dispatch process and the role of forecasting in this process.

The frequency impacts of variations in non-dispatchable capacity[182] that create imbalances in supply and demand within the five minute dispatch interval are currently managed through the provision of regulating FCAS. AEMO's 2016 *National transmission network development plan* noted that with continued growth in non-dispatchable capacity, the size and number of continuous minor supply demand imbalances is expected to grow.[183] Sudden changes in output from non-dispatchable capacity within a dispatch interval could potentially increase the level of uncertainty in the dispatch process, which may increase the amount of FCAS needed to maintain frequency within the requirements of the frequency operating standard.

6.2.2 Stakeholder views

The issues paper sought stakeholder views on options to manage the frequency impacts of the variability of non-dispatchable capacity within the five minute dispatch interval. Specifically, the AEMC questioned whether it would be more efficient to improve the forecasting of non-dispatchable capacity to reduce imbalances in supply and demand, or to rely on higher levels of regulating FCAS to manage those imbalances.

Most stakeholders considered that better forecasting would help to manage the frequency impacts of the variability of non-dispatchable capacity within the five minute dispatch interval.[184]

Several stakeholders submitted that AEMO's Australian wind energy forecasting system (AWEFS) provided questionable forecasts that feed directly into the dispatch engine and therefore may be a driver of scheduling error.[185]

S&C Electric Company submitted that improved forecasting of demand and generation would help to deliver system balancing at lowest cost, but that the more pressing issue to resolve is maintaining frequency within the normal operating frequency band.[186]

---

182 The term, 'non-dispatchable capacity' is used in this paper to collectively refer to semi-scheduled generators, non-scheduled generators and or behind-the-meter rooftop solar PV systems, as well as changes in demand due to the operation of home energy management systems or energy storage systems.

183 AEMO, National transmission network development plan, December 2016, p. 61. Note AEMO is only referring to semi-scheduled and non-scheduled generation, and rooftop solar PV.

184 Submissions to issues paper: Australian Energy Council, p. 2; Energy Queensland, p. 6; Hydro Tasmania, p. 10; Snowy Hydro, p. 11; TasNetworks, p. 15.

185 Submissions to issues paper: Meridian Energy, p. 9; Pacific Hydro, p. 13.

In relation to the trade-off between improved forecasting and reliance on higher levels of regulating FCAS, TasNetworks submitted that "you would do both" at the outset and then apply the "95 per cent rule" – that is, at some point the costs and effort required to improve the forecasting models to gain a relatively small improvement in performance will outweigh the costs of mitigating the error via dispatching more regulating FCAS.[187] Hydro Tasmania and EnergyAustralia shared a similar view, noting that by definition, forecasts will never be correct, but that work can be done to improve their accuracy in conjunction with changes to regulating FCAS.[188]

Pacific Hydro was of the view that the forward availability of renewable plant for dispatch and near term forecasting should be performed by participants themselves, as they are best placed to provide this information with accuracy.[189]

The Clean Energy Council proposed a similar approach, noting that a participant's contribution factors[190] for the recovery of regulating FCAS costs are calculated by comparing the measured generation of each wind farm against the aggregate forecast from AWEFS, not the wind farm's expected performance. It was of the view that this approach:

- creates risks from causer-pays costs that wind farms cannot take action to control/limit manage their contribution factors because there is a lack of transparency in terms of how the AWEFS calculation works
- discourages active participation in the energy and FCAS markets from semi-scheduled generators by promoting a set-and-forget approach to operation
- increases the need for FCAS by artificially creating dispatch errors because NEMDE is comparing actual generation to modelled aggregate generation, not expected generation.

The Clean Energy Council proposed that a more efficient approach would be to allow semi-scheduled generators to bid into NEMDE to override the AWEFS calculation with their own expected generation for the coming immediate dispatch intervals (e.g. 5-15 minutes ahead). This is because, in many instances, individual wind farms have better information about the operation of their plant and local resource conditions. The Clean Energy Council was of the view that such an approach would enable participants to

186 S&C Electric Company, submission to issues paper, p. 10.

187 TasNetworks, submission to issues paper, p. 15.

188 Submissions to issues paper: EnergyAustralia, p. 6; Hydro Tasmania, p. 10.

189 Pacific Hydro, submission to issues paper, p. 13.

190 Contribution factors for semi-scheduled generators are based on the generator's performance with respect to their dispatch targets that are based on the generation forecast from AWEFS for wind generation and ASEFS for solar generation. See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

better manage risks, while also reducing forecasting error and demand for regulating FCAS.[191]

Energy Queensland noted that much of the analysis in the issues paper was of wind output, and submitted that it is unlikely that large scale solar PV output changes more rapidly than wind output. It highlighted the ability of modern forecasting tools to forecast solar output at a more local level, and noted that skycams and satellite tools are being used in island networks such as Hawaii to do immediate and long-range solar forecasting.[192]

Meridian Energy proposed that solar installations be metered to enable better forecasting of their output during each five minute dispatch interval.[193]

6.2.3 Analysis and proposed solution

Forecasting is an integral part of NEM operations. Accurate forecasts help AEMO to manage the supply/demand balance and amongst other things keep frequency within the requirements of the frequency operating standard.

In relation to frequency, more accurate forecasting of the output of non-dispatchable capacity is likely to minimise imbalances between supply and demand, which is likely to minimise the amount of FCAS required to manage frequency deviations within a dispatch interval. The Commission considers that, in the first instance, changes that seek to improve the accuracy of demand and supply forecasting are likely to be a more efficient means of managing the expected increase in supply and demand variations within a dispatch interval than procuring more regulating FCAS.

However, forecasts will never be 100 per cent accurate. The costs of attempting to achieve close to 100 per cent accuracy within the dispatch time frame for each generator and load in the NEM are likely to be significant, and at some point are likely to outweigh the costs of mitigating the variation by dispatching more regulating FCAS. The objective should therefore be to make dispatch demand forecasts as accurate as is efficient, and then use regulating FCAS to make up any difference.

Through the *Non-scheduled generation and load in central dispatch* rule change, the Commission engaged the University of Wollongong to review AEMO's demand forecasting model. The study concluded the model is out-dated and not able to account for volatility, price spikes and price response.[194] This advice indicates that there is scope for substantial upgrading of AEMO's forecasting model which is likely to contribute to more accurate forecasting of generation and load in the NEM.

191 Clean Energy Council, submission to issues paper, p. 3.

192 Energy Queensland, submission to issues paper, p. 6.

193 Meridian Energy, submission to issues paper, p. 9.

194 AEMC, *Non-scheduled generation and load in central dispatch* rule change - determination, 12 September 2017, p.45.

The accuracy of forecasting and whether concerns about its accuracy are having an impact on reliability outcomes is being explored by the AEMC through the *Reliability frameworks review*. In the interim report published in December 2017, the AEMC concluded that it may be worthwhile exploring ways in which variations between supply and demand can be better managed through the forecasting process, or alternatively, whether there are ways to be less reliant on centrally managed forecasts, for example by:[195]

- allowing semi-scheduled generators to provide AEMO with 'offers' of their availability, which could help to mitigate the risks of unexpected events such as cloud cover[196]
- allowing AEMO to request more information from retailers or aggregators about any distributed energy resources they have contracted with
- requiring retailers themselves to forecast the expected demand of their customers, and to submit bids to AEMO to be 'dispatched'.

The interim report also welcomed the range of improvements AEMO has made, and intends to make, to its forecasting processes, which largely relate to longer-term forecasts than those used in dispatch.

Submissions to the *Reliability frameworks review* interim report closed on 6 February 2018. In general, submissions to the Reliability frameworks review interim report acknowledge that forecasting is becoming harder with a greater take up of renewable energy and distributed energy resources. Stakeholders support the AEMC undertaking more analysis on the accuracy of forecasts and investigating potential reforms that are likely to contribute to improvements in the accuracy of supply and demand forecasting.

The Commission plans to publish a directions paper for the *Reliability frameworks review* on 27 March 2018, which will include further detail and analysis on the forecasting work stream. This progress of that work will be relevant to this aspect of this review, and any final recommendations in this review will be informed by it.

195 AEMC, Reliability frameworks review – interim report, pp. 74, 76.

196 The Commission understands that AEMO is partnering with ARENA to explore the potential for semi-scheduled generators (such as utility-scale wind and solar projects) to voluntarily 'self-forecast' their expected generation for the upcoming dispatch interval. AEMO notes that allowing such generators to do this could, among other things, reduce FCAS costs and improve system security outcomes.

7 Participation of distributed energy resources in system security frameworks

This chapter sets out:

- an overview of the potential for distributed energy resource participation in system security frameworks
- a summary of stakeholder comments on distributed energy resources in submissions to the issues paper
- the Commission's analysis and recommendations in relation to:
  - aggregator frameworks for distributed energy resources
  - the market ancillary services specification (MASS)
  - connection arrangements for distributed energy resources
  - the technical impacts of distributed energy resources providing system security services.

7.1 Overview

As set out in Chapter 3, the electricity industry in Australia is undergoing fundamental change. In addition to the withdrawal of large synchronous generators, there has been a rapid and ongoing uptake of distributed energy resources.[197] This has predominantly consisted of distributed solar photovoltaic (PV) systems, but is increasingly including other technologies such as batteries and electric vehicles. These technologies are changing the way in which consumers draw electricity from, and export electricity to, the broader power system. Distributed energy resources bring with them challenges and opportunities for power system security.

A key focus of the *Frequency control frameworks review* is on the opportunities for distributed energy resources to support power system security. As the power system changes many of the necessary system security services may need to be sourced from new providers, such as distributed energy resources.

Through this review, the AEMC and stakeholders have identified aspects of the current regulatory and market frameworks that may be inefficiently limiting the provision of system security services from distributed energy resources. These include:

- An absence of market participant categories that permit aggregated small generating units to offer market ancillary services. While there are two existing

197 Distributed energy resources do not have a universally agreed upon definition. For this review, the term describes "an integrated system of energy equipment that is connected to the distribution network", which is consistent with the definition used in the AEMC's *Distribution market model* project. See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

frameworks in the NER that provide for the aggregation of distributed energy resources, neither accommodates the aggregation of small generating units for the purpose of providing market ancillary services. As a result, distributed energy resources that are capable of exporting electricity to the network are not currently able to be aggregated to offer market ancillary services.

- Size requirements for market ancillary service offers. The NER currently requires market ancillary service offers to be made in whole megawatts (MWs). This may present a barrier to aggregators with distributed energy resource capacity in increments other than whole MWs.
- Inconsistent and unclear application of connection frameworks and the relevant Australian Standards. These frameworks, and DNSPs' own connection requirements, do not appear to value or incentivise the provision of system security services by distributed energy resources.
- The potential underutilisation of market ancillary services from newer technologies. AEMO's MASS potentially presents barriers to the provision of system security services from distributed energy resources, and may not appropriately account for the ability for new technologies (such as storage) to provide a fast frequency response.

This chapter explores each of these issues in turn, makes recommendations on possible changes to address them (if necessary) and seeks stakeholder feedback. It also highlights the complexity associated with the participation of distributed energy resources in system security frameworks. Sourcing system security services from within a distribution network is likely to have localised impacts that need to be further considered. As explained in section 7.3, this review is not considering the impacts of distributed energy resources on the need for system security services.

7.2 Context

The capacity of distributed energy resources continues to grow in the NEM. A formerly passive demand side is becoming increasingly engaged through the uptake of solar PV, storage and demand response. These technologies are greatly expanding the choices that consumers have to manage their energy needs at the household/business level. In aggregate, they have the potential to provide value to consumers and NEM participants through the provision of wholesale services (such as FCAS) or network services (such as network congestion management).

Aggregated distributed energy resources are currently providing services to the rest of the power system, such as reducing load at peak times or correcting an imbalance in power system frequency.[198] The South Australian government has announced the intention to roll out a virtual power plant, which would consist of residential PV and

198 For example, EnerNOC is using aggregated demand response to participate in FCAS markets and Reposit is using aggregated residential storage to alter retailer exposure to high spot prices.

storage being installed and aggregated across at least 50,000 houses.[199] The virtual power plant is expected to have approximately 250MW of total installed capacity, which is comparable to the capacity of a peaking generator. While the South Australian government has not announced the intention for the virtual power plant to provide system security services, it will result in greater quantities of aggregated distributed energy resources installed in the distribution network with that potential.

At the same time, a number of large transmission-connected synchronous generators have retired, and a number more are expected to do so. As explained in section 3.1.1, these generators have traditionally provided the system services necessary for the secure operation of the power system. As these generators retire, there may be more opportunities for distributed energy resources to participate in the provision of system security services. This need could become particularly acute in regions where the output of distributed energy resources is reducing minimum operational demand,[200] which consequently reduces the amount of generation provided through central dispatch from conventional sources.

The Finkel Panel Review, published in June 2017, recommended that by mid-2019 the AEMC "review the regulatory framework for power system security in respect of distributed energy resources, and develop rule changes to better incentivise and orchestrate distributed energy resources to provide essential security services such as frequency and voltage control".[201]

The potential for distributed energy resources to support power system security has also been recognised by AEMO through its Future Power System Security work program, the AEMC in the final report of its *Distribution market model* project and Energy Networks Australia in its *Electricity network transformation roadmap*.[202]

7.3 Role of distributed energy resources in system security frameworks

7.3.1 Overview

In undertaking this work stream, the Commission acknowledges that the potential large-scale provision of system security services by distributed energy resources is a relatively recent consideration, for which the technical requirements are not fully understood and may evolve over time. This may place some limitations on the extent

---

199 For more information see: http://ourenergyplan.sa.gov.au/virtual-power-plant

200 Operational demand refers to electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units. It does not include demand met by residential PV.

201 Independent Review into the Future Security of the National Electricity Market, final report, June 2017, pp. 62-63.

202 See: AEMO, *Visibility of distributed energy resources*, January 2017, p. 17; AEMC, *Distribution market model*, final report, p. 72; Energy Networks Australia / CSIRO, *Electricity network transformation roadmap*, final report, April 2017, pp. 52-63.

to which frameworks for the provision of system security services by distributed energy resources can be properly assessed and formulated through this review.

Nevertheless, the Commission considers that the regulatory arrangements for the provision of system security services from distributed energy resources should continue to be investigated as the technical understanding evolves.

As system security services have traditionally been provided by large, transmission-connected generators, the Commission acknowledges that the existing regulatory frameworks may not enable these services to be provided by distributed energy resources. This review provides an opportunity to consider the extent to which these frameworks might present a barrier to distributed energy resources providing system security services and whether those barriers are inefficient.

This review also provides an opportunity to put frameworks in place that allow for distributed energy resource participation where appropriate, in advance of a pressing need. Consequently, the development of aggregator business models and investments in distributed energy resources should be able to factor in the opportunity to participate in system security frameworks. A forward-looking review of frameworks should partially alleviate the need to revisit regulatory frameworks as new, innovative technology and service providers look to participate in system security frameworks.

Recent developments in FCAS markets have demonstrated the impacts of allowing new service providers to participate. In the past year both utility-scale storage and aggregated demand response have started offering services into FCAS markets.

Allowing new participants into these markets increases competition for the provision of FCAS. By making the markets for ancillary services more competitive, the prices paid for these services should fall and consequently reduce costs for consumers. It should also result in investment and operational decisions being made by the owners and operators of distributed energy resources in a manner that contributes to power system security and provides value for the required services.

7.3.2 Impact of distributed energy resources on system security

AEMO has noted that the uptake of distributed energy resources will have a "material and unpredictable" impact on the power system if it is not "managed holistically".[203] In its submission to the issues paper, AEMO highlighted some of the implications of increasing levels of distributed energy resources. For example, it noted that there are likely to be times over the next ten years when few of the remaining synchronous generators are online due to high levels of distributed energy resources generation.[204] AEMO considered that the growing penetration of distributed energy resources and other non-synchronous generation will affect the needs of the system, and hence the design of frameworks.

203 AEMO, *Visibility of distributed energy resources*, January 2017.

204 AEMO, submission to issues paper, p. 8.

The Commission considers that it is important for AEMO to look at these issues to support the ongoing secure operation of the power system. However, this review does not focus on ways to mitigate the adverse impacts of distributed energy resources on AEMO's ability to maintain power system security. AEMO has a program of work underway to understand and manage these challenges. The Commission will work closely with AEMO and consider any outcomes or recommendations of that work within the time frames of this review.

This review focuses instead on how the frameworks under which distributed energy resources connect, operate and participate in the NEM can be designed so as to enable the efficient provision of system security services by distributed energy resources. Nevertheless, the Commission acknowledges that the aggregated provision of system security services using distributed energy resources may have consequential impacts on networks and broader system security. For example, the use of distributed energy resources for FCAS might cause local over-voltage issues within the distribution network.

Distribution networks will likely always have physical limits that, in some cases, will constrain a market-delivered optimisation of the many valued services that distributed energy resources are capable of providing. The AEMC's *Distribution market model report* explored how these services could be co-optimised with the need for the distribution network service provider to maintain a safe, secure and reliable network - that is, how a distributed energy resource's operation could be maximised in light of these constraints.[205] The nature of distribution networks' technical constraints will therefore need to be better understood and communicated with aggregators of distributed energy resources before the large-scale provision of system security services from distributed energy resources can occur. This is discussed in more detail in section 7.7.

In submissions to the issues paper, stakeholders provided feedback on some of the technical and commercial challenges being faced, or likely to be faced, by distributed energy resources providing system security services. These comments are set out in sections 5.2.4 and section 5.2.5 of the progress update for the review.[206] While this feedback has informed the Commission's understanding of the issues, the commercial or technical challenges that exist outside the regulatory frameworks associated with the provision of system security services from distributed energy resources are not matters for the Commission to consider as part of this review. However, the Commission considers that regulatory frameworks that value required services from distributed energy resources would provide the opportunity for participants to address these challenges.

205 See: https://www.aemc.gov.au/markets-reviews-advice/distribution-market-model

206 AEMC, *Frequency control frameworks review - progress update*, December 2017, pp. 33-34.

7.3.3 Stakeholder submissions on the role of distributed energy resources

In submissions to the issues paper, stakeholders were generally supportive of increased participation of distributed energy resources in system security frameworks.[207]

AEMO considered that the growing penetration of distributed energy resources and other non-synchronous generation will affect the needs of the system, and hence the design of frameworks. It noted that there are likely to be occurrences over the next ten years when few of the remaining synchronous generators are online due to high levels of distributed energy resources generation.[208]

Snowy Hydro and the Australian Energy Council suggested that for distributed energy resources to be able to participate in system security frameworks there should be effective market mechanisms for procuring the desired services in a technology neutral manner, allowing for the least cost provision of system security services.[209] Energy Queensland shared a similar view, submitting that while the regulatory framework does not necessarily inhibit distributed energy resources from providing system services, it has not been explicitly considered to date, so it is likely that incentives will be needed for distributed energy resources to provide capability beyond any minimum requirements.[210]

Stanwell requested that the Commission urgently review how to best integrate demand response and distributed energy resources into the market such that their impact on frequency is better accounted for and addressed.[211] The Clean Energy Council submitted that the review should seek to remove barriers to participation in frequency control markets by aggregators and distributed energy resources generally, and seek to design market-based solutions that encourage participation by aggregators and distributed energy resources.[212]

S&C Electric Company asked the Commission for evidence of the ability for distributed energy resources to provide system restart services, a service that was suggested distributed energy resources could provide in the issues paper. It noted that they were not aware of any aggregated small-scale systems that have successfully delivered black start services.[213] S&C Electric Company also suggested that inertia would not be able to be provided by distributed energy resources, and that it is unlikely that they would be able to provide primary frequency control.[214] However, it

---

207 Submissions to issues paper: AEMO, p. 9; AGL, p. 2; Energy Network Australia, p. 2; Tesla, p. 8; TasNetworks, p. 2; Snowy Hydro, p.12; Australian Energy Council, p. 2.

208 AEMO, submission to issues paper, p. 8.

209 Submissions to issues paper: Snowy Hydro, p.12; Australian Energy Council, p. 2.

210 Energy Queensland, submission to issues paper, p. 11.

211 Stanwell, submission to issues paper, p. 3.

212 Clean Energy Council, submission to issues paper, p. 5.

213 S&C Electric Company, submission to issues paper, p. 2.

214 The Commission considers that distributed energy resources may include synchronous generators connected to the distribution network, which would provide inertia.

noted that frequency control on longer time scales (e.g. secondary[215]) may be possible, noting that it cannot be assumed that all distributed energy resources, regardless of size, can deliver a frequency service and that the primary operational intent of distributed energy resources is managing energy costs.[216]

7.4 Aggregator regulatory frameworks

Some system security services (e.g. frequency or voltage control) can be provided by a change in active or reactive power output or consumption. For example, a distributed energy resource could assist with the maintenance of power system frequency by increasing active power output or lowering consumption to raise power system frequency, or reducing output or increasing consumption to lower power system frequency.

These services could be provided by an individual distributed energy resource, but are likely make a more material contribution to maintaining power system security through aggregation. The value of system security services provided by an individual distributed energy resource would likely be outweighed by the costs and complexity associated with participation in any centrally dispatched mechanism. Aggregation of distributed energy resources provides an opportunity for participation in system security frameworks with an aggregator providing the interface between the distributed energy resources and AEMO.

As explained in section 2.1.2, there are two types of ancillary services provided in the NEM: market and non-market ancillary services. Non-market ancillary services provide (black) system restart and network support (e.g. voltage control) services, and are provided by parties under contract with AEMO. Market ancillary services are concerned with the timely injection (or reduction) of active power to arrest a change in frequency, and currently comprise only the eight FCAS services described in section 2.1.2. In the issues paper for this review, the AEMC concluded that there do not appear to be any barriers in the NER to prevent a Market Small Generation Aggregator or a Market Ancillary Service Provider (the two frameworks discussed in this section) from tendering or applying to AEMO to provide non-market ancillary services.[217] The remainder of this section therefore focuses on the provision of market ancillary services (e.g. FCAS) under these frameworks.

This section outlines:

- the Commission's views on issues with the existing aggregator regulatory frameworks that may be inhibiting the provision of market ancillary services via distributed energy resources

215 See section 2.2.

216 Ibid, pp. 11-13.

217 See section 7.3 of the issues paper for this review. See: https://www.aemc.gov.au/sites/default/files/content/0fd91c30-bc61-4d53-8ee3-249eac0123b5/Issues-paper.pdf

- stakeholder views on these matters
- the Commission's proposed approach to addressing the identified issues.

7.4.1 Issues

Existing aggregator frameworks

The issues paper set out two existing frameworks in the NER that facilitate distributed energy resource aggregation: the Small Generation Aggregator framework and the Market Ancillary Service Provider framework.[218]

Small generation aggregator framework

A Small Generation Aggregator is a market participant who is able to sell the output of multiple small generating units[219] through the NEM without the expense of individually registering each generating unit.[220] This enables small generating units to have more direct exposure to market prices, and therefore creates a more efficient wholesale market. Distributed energy resources that export electricity via a distribution network (e.g. a battery storage system) would be captured by the definition of small generating unit.

Under the framework, a person who intends to supply electricity from one or more small generating units to a transmission or distribution system may register as a Small Generation Aggregator.[221] A Small Generation Aggregator must classify one or more small generating units as a market generating unit, each with a separate connection point,[222] and when it does so it becomes the financially responsible market participant at that connection point.

To provide market ancillary services (e.g. FCAS), a generating unit must be classified as an ancillary service generating unit. Under the NER, only Market Generators can apply to AEMO for approval to classify a generating unit as an ancillary service generating unit. As a Market Small Generation Aggregator is not a Market Generator, it is not able to apply to classify small generating units as ancillary service generating

218 For more information on these frameworks see the issues paper, pp. 112-116.

219 Small generating unit is defined in Chapter 10 of the NER as "a generating unit with a nameplate rating that is less than 30MW; and which is owned, controlled or operated by a person that AEMO has exempted from requirement to register as a Generator in respect of that generating unit in accordance with clause 2.2.1(c)."

220 In November 2012 the AEMC made a final determination and final rule on the *Small generation aggregator framework* rule change request. The rule commenced on 1 January 2013. The objective of the rule change was to reduce the barriers faced by the owners of small generators to actively participate in the NEM. See: http://www.aemc.gov.au/Rule-Changes/Small-Generation-Aggregator-Framework

221 See clause 2.3A.1(a) of the NER.

222 See clause 2.3A.1(e) of the NER.

units. As a result, a Market Small Generator Aggregator is not able to provide market ancillary services by means of a small generating unit.

Market Ancillary Service Provider framework

On 1 July 2017 the provision of ancillary services was unbundled from the provision of energy.[223] The unbundling framework provides for a new type of market participant – a Market Ancillary Service Provider – who can offer appropriately classified ancillary services loads or aggregation of loads into the market ancillary service markets (i.e. the FCAS markets) without having to be the financially responsible market participant at that connection point. The intention of the rule was to enable a more diverse group of suppliers to provide market ancillary services, which would enhance competition in these markets and better enable AEMO to manage the frequency of the power system.

The Market Ancillary Service Provider is required to satisfy certain registration requirements, deliver FCAS services in accordance with AEMO's specifications, just as any other market participant is required to do, and submit FCAS offers to the relevant FCAS markets in accordance with the provisions in the NER. AEMO's technical specifications may have previously been interpreted as preventing regulating FCAS from being provided through the aggregation of loads. AEMO considered that this was not the case but committed to clarifying this. AEMO did so through its *Review of the market ancillary service specification* and the revised market ancillary service specification, effective from 30 July 2017, sets out the process required for aggregated ancillary service facilities to provide regulating FCAS.[224]

A subsequent rule change request was submitted by AEMO in April 2017. The *Classification of loads as ancillary services loads* rule, which commenced on 29 August 2017, allows any load to be eligible for classification as an ancillary services load.[225] It removed the restriction that only a market load could be classified by a Market Ancillary Service Provider as an ancillary service load.

A Market Ancillary Service Provider can offer to provide market ancillary services through appropriately classified ancillary services loads or aggregation of loads. A Market Ancillary Service Provider does not have to become the financially responsible market participant for the loads being offered. As a result, there do not appear to be any regulatory barriers to a load, including individual residential and small business loads, from providing market ancillary services, if it is provided by a Market Customer or Market Ancillary Service Provider. However, a Market Ancillary Service Provider is not able to aggregate generating units for the purpose of classifying them as ancillary service generating units and providing market ancillary services.

---

223 In November 2012 the AEMC made a final determination and final rule on the *Demand response mechanism and ancillary services unbundling* rule change. See: http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

224 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Amendment-Of-The-Market-Ancillary-Service-Specification

225 See: http://www.aemc.gov.au/Rule-Changes/Classification-of-loads-as-ancillary-service-loads

Issues associated with existing aggregator frameworks

While these frameworks provide for the aggregation of distributed energy resources, neither accommodate the aggregation of small generating units for the purpose of providing market ancillary services. As a result, distributed energy resources that are capable of exporting electricity to the network are not able to be aggregated to offer market ancillary services. This may be resulting in the underutilisation of distributed energy resources in the provision of these services.

Whole MW bid requirement

Another regulatory issue that may present a barrier to the provision of market ancillary services by distributed energy resources is a requirement in the NER for market ancillary service offers to be in whole MW increments.[226] This may limit the ability for an aggregator to incrementally change the size of its market ancillary service offers as the size of its portfolio changes. The NER also requires a minimum offer of a whole MW, which would exclude the participation of aggregators with portfolios with less than 1MW of available capacity.

7.4.2 Stakeholder views

Stakeholders provided limited feedback on potential issues with the NER's aggregator regulatory frameworks in submissions to the issues paper.

Energy Networks Australia noted that the requirement to offer market ancillary services in 1MW increments may be an issue for aggregator portfolios.[227] TasNetworks also noted that the 1MW requirement may have limited the number of FCAS trials from aggregated distributed energy resources.[228]

7.4.3 Analysis and proposed solution

The Commission considers that there may be benefits in allowing both Small Generation Aggregators and Market Ancillary Service Providers to offer market ancillary services from small generating units.[229]

Small Generation Aggregators and Market Ancillary Service Providers have different characteristics. Small Generation Aggregators tend to aggregate small generating units in order to participate in the wholesale electricity market. These generating units have their own connection points for which the Small Generation Aggregator becomes the

226 Clause 3.8.7A(i) of the NER requires market ancillary service offers to be made in whole MWs.

227 Energy Networks Australia, submission to issues paper, p. 10.

228 TasNetworks, submission to issues paper, p. 17.

229 The Commission has previously recommended that Small Generation Aggregators be able to provide market ancillary services. See: AEMC, *Integration of storage*, final report, December 2015, p. 24.

financially responsible market participant.[230] Small Generation Aggregators are able to sell generation into the wholesale market and receive the spot price. They are required to satisfy the relevant prudential requirements in Chapter 3 of the NER.[231]

By contrast, a Market Ancillary Service Provider is not able to aggregate resources for the purpose of participating in the wholesale electricity market. Instead, a Market Ancillary Service Provider is able to aggregate loads to provide market ancillary services without also becoming the financially responsible market participant at the connection point for those resources.[232] In addition, Market Ancillary Service Providers are not required to meet certain prudential requirements in the NER because they are not the financially responsible market participant for the relevant load and therefore do not incur charges for the electricity consumed by that load in the NEM.[233]

In the Commission's view, allowing both Small Generation Aggregators and Market Ancillary Service Providers to offer market ancillary services using small generating units provides flexibility for a range of business models that may emerge in this space - that is, parties who want to take on the role of financially responsible market participant and also participate in the wholesale electricity market, and those who do not wish to take on the role of financially responsible market participant.

It also provides flexibility for aggregators of resources of different sizes. As a result of the requirement to also be the financially responsible market participant, the Commission understands that Small Generation Aggregators tend to aggregate 'larger' small generating units, for example on behalf of commercial or industrial customers. By contrast, the Market Ancillary Service Provider framework may be more suited to

230 For residential customers, the financially responsible market participant is typically a retailer.

231 A market generator is subject to clause 3.3 of the NER, which sets out prudential requirements on market participants. As a market generator has to pay participant fees and may generate at times when the spot price is negative, it will owe AEMO a certain amount every month. However, a generator’s maximum credit limit (the minimum amount of credit support a market participant must provide to AEMO) is highly likely to always be negative – that is, AEMO will net owe the generator rather than the other way around. For this reason, the generator will not be required to meet the acceptable credit criteria and provide credit support, or be subject to the bulk of the prudential requirements in clause 3.3. However, small generation aggregators who are also market customers will be subject to these prudential requirements in relation to their load.

232 The Commission notes that there may be benefit to allowing multiple financially responsible market participants behind a connection point. The Commission is considering this in its *Reliability frameworks review*.

233 Market Ancillary Service Providers are subject to the prudential requirements in clause 3.3.1 of the NER, specifically that they must be resident in Australia; not be immune from suit in respect of their obligations under the NER; and be capable of being sued in their own name in Australia. As Market Ancillary Service Providers are not exposed to the wholesale electricity market and do not accrue a settlement payment obligation in the NEM, they are not subject to the prudential requirements in clauses 3.3.2 to 3.3.19 of the NER and are not required to provide credit support. This was noted in AEMO's submission to the draft determination for the *Demand response mechanism and ancillary services unbundling* rule change, where AEMO noted that no providers of market ancillary services provide credit support or have prudential requirements. AEMO, submission to the *Demand response mechanism and ancillary services unbundling rule change - draft determination*, p. 3.

'smaller' small generating units (such as households), where the consumer retains a separate relationship with a retailer (i.e. the financially responsible market participant).

It is likely that one of these frameworks will be more suitable or valuable to a participant and its customers than another. Allowing both Small Generation Aggregators and Market Ancillary Service Providers to offer market ancillary services using small generating units provides flexibility to potential aggregators to register in the category that reflects their business case and intended service offerings.

The participation of Market Ancillary Service Providers in ancillary service markets to date suggests that aggregated resources can successfully be accommodated within this framework. An example of this is provided in Box 7.1. For this reason, the Commission considers there to be no reason why Market Ancillary Service Providers should be precluded from classifying small generating units as ancillary service generating units for the purposes of providing market ancillary services.

Box 7.1 EnerNOC providing contingency FCAS

EnerNOC is a provider of energy intelligence software and demand response services, including services that assist with frequency control.

By reducing the consumption of some demand-side loads, EnerNOC has been able to offer frequency raise services in the NEM FCAS markets. These demand-side electricity loads, typically commercial and industrial customers, are able to be communicated with remotely and if needed, turned down.

For EnerNOC to utilise a load for frequency control services, it must install a device that connects to the load and monitors grid frequency. The device will rapidly reduce load following a trigger condition (such as a measurement of low frequency). The disconnection of load assists in arresting the fall in frequency, having the same effect of a rapid increase in generation of the same magnitude.

Following the Commission’s final rule on the *Demand response mechanism and ancillary services unbundling* rule change request, EnerNOC has registered as a Market Ancillary Service Provider. EnerNOC has also aggregated a portfolio of demand-side loads that are able to be turned down from a signal to do so. As a registered Market Ancillary Service Provider, EnerNOC is now bidding in FCAS markets by offering a reduction in load. EnerNOC is offering six-second, 60-second and five-minute raise frequency services. If these contingency services are enabled by AEMO, they may be used following a fall in power system frequency.

A rule change would be needed to facilitate the changes necessary to allow both Small Generation Aggregators and Market Ancillary Service Providers to use small generating units to provide market ancillary services.[234] In the Commission's view, such changes should:

- lead to greater competition in FCAS markets, potentially leading to lower FCAS costs
- diversify the providers of these services
- provide greater value to the owners of distributed energy resources
- result in more efficient operational decisions for the controllers of distributed energy resources.

Draft recommendation 4

That a rule change request be submitted to enable:

(a) Market Ancillary Service Providers to classify small generating units as ancillary service generating units for the purposes of offering market ancillary services

(b) Small Generation Aggregators to classify small generating units as ancillary service generating units for the purposes of offering market ancillary services.

These changes may also require changes to AEMO's MASS.

Whole MW bid requirement

Some stakeholders have suggested that the requirement for market ancillary services bids to be made in 1MW increments may present a barrier to distributed energy resources providing these services. Restricting bids to 1MW increments requires an aggregator to build up a portfolio of at least 1MW, and then subsequently constrains their ability to increase their offers in line with changes in their portfolios. For example, an aggregator may acquire new customers that allow it to offer 2.5MW of FCAS. Under the current arrangements, until that aggregator is able to acquire another 0.5MW of capacity, the full capability of the resources under control of the aggregator may be underutilised.

As set out above, this requirement is set out in the NER and, as such, a rule change would be required to amend or remove it. One possible option were it to be removed would be for AEMO to set out the minimum and incremental offer sizes in a separate AEMO guideline.

However, at this stage, it is unclear to the Commission whether the benefits of reducing or removing this requirement would outweigh the costs. Many of the market

234 These changes would likely have to be made in Chapter 2 of the NER, but other consequential changes may be necessary.

and regulatory arrangements for the provision of market ancillary services, and AEMO's systems that reflect these arrangements, are aligned with those for the provision of energy through the wholesale electricity market. Consideration of whether to reduce or remove the whole MW offer requirement for market ancillary services would therefore need to be undertaken in conjunction with consideration of whether this remains appropriate for energy market offers.

Further, while reducing the minimum offer size may increase the number of participants in ancillary service markets, these participants would still be required to register as market participants, pay registration fees and be subject to the rule requirements relevant to their registration. It is therefore not clear to the Commission whether the value to participants of being able to offer less than one MW of a market ancillary service would outweigh these costs.

The Commission seeks stakeholder views on whether this rule poses an inefficient barrier to the provision of market ancillary services using distributed energy resources, specifically the requirement for aggregators to:

- achieve an initial minimum offer size of 1 MW
- subsequently only offer in whole MW as the size of the aggregation portfolio increases.

The Commission also seeks stakeholder views on any costs, benefits or risks associated with removing or amending this requirement.

7.5 Market ancillary services specification (MASS)

Currently market ancillary services address frequency control.[235] In providing frequency control services, a participant must comply with both the NER and AEMO's market ancillary service specification.

The Commission is investigating whether the requirements in the MASS might constitute a barrier for distributed energy resources looking to provide market ancillary services.

This section outlines:

- the requirements in the MASS
- stakeholder views on the ability for distributed energy resources to provide market ancillary services under the MASS
- the AEMC's proposed approach to addressing the identified issues.

235 See section 2.1.2.

7.5.1 The requirements in the MASS

AEMO is required under the NER to publish the MASS containing at a minimum:[236]

- a detailed description of each kind of market ancillary service
- the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant market ancillary service and also when a market participant provides the relevant kind of market ancillary service.

The MASS sets out the more detailed specification of the market ancillary services and how a market participant's performance is measured and verified when providing these market ancillary services. The MASS is not intended to act as a technical specification for providing market ancillary services. Instead, its purpose is to describe in more detail the requirements of each service, and how the provision of a market ancillary service should be measured and verified.

AEMO also publishes an FCAS verification tool to help participants calculate the level of FCAS that can be delivered by their plant in accordance with the principles in the MASS. This verification tool does not form part of the MASS but contains algorithms that are used by AEMO to verify the contingency services provided by a market ancillary service facility.[237] Participants are required to nominate the quantity of FCAS that they are able to provide into each FCAS market. To be registered and subsequently enabled to provide that FCAS, AEMO needs to determine that the participant is capable of providing these quantities. Participants are able to use the FCAS verification tool to calculate the amount of FCAS they would like AEMO to be able to enable them for in each FCAS market.

The MASS requires the equipment used to monitor and record the response of ancillary service facilities to:[238]

- measure the power flow at or close to the connection point of the ancillary service generating unit or load
- measure local frequency at or close to the relevant connection point, unless otherwise agreed by AEMO
- measure local power and frequency at:
  - intervals of 50ms for fast raise and lower services[239]

236 Clause 3.11.2(b) of the NER.

237 AEMO, *Market ancillary service specification*, July 2017, p. 12.

238 Ibid.

239 If agreed with AEMO, where a switching controller is used, the measurement of power flow representing the generation amount or load amount may be made at intervals of up to four seconds. This is provided that another measurement of power flow at an interval of 50ms or less is provided sufficient to determine the timing of the market ancillary service provision relative to local frequency. For example, where FCAS is being provided by an interruptible load, AEMO may

— intervals of four seconds for regulating, slow and delayed raise and lower services.

7.5.2 Stakeholder views

A number of stakeholders suggested in submissions that the MASS may impose limitations on the services that could be provided by aggregated distributed energy resources.

Meridian Energy asked that the AEMC give consideration to how distributed energy resources could provide FCAS without the requirement for uneconomic metering.[240] Tesla raised a similar issue, noting that AEMO requires "industrial-grade meters" for demand side participation, which is cost-prohibitive for residential distributed energy resources.[241] AGL also suggested that measurement and verification of output every 50ms for providing FCAS is unnecessary because:[242]

- it is difficult to source distributed energy resources that can provide measurements at 50ms speed
- one second data is widely used in other jurisdictions
- AEMO has not adequately justified why 50ms is necessary
- with larger amounts of aggregation, this is going to increase the amount of information that will be sent to AEMO.

TasNetworks noted that it is not practical to test and commission a block of distributed energy resources and declare it to have a completely 'known' characteristic across all operating conditions.[243]

Tesla also highlighted some broader issues with the MASS and the implications this had for utility scale storage, submitting that:[244]

- the maximum registration amount for FCAS enablement is based on a theoretical frequency ramp that is not representative of the current power system
- this limitation is present in the MASS and accompanying FCAS verification tool
- this limitation undervalues the capability of energy storage frequency response.

---

not require high speed monitoring of the actual power flow to the load if high speed monitoring can be used to demonstrate when the load was switched off.

240 Meridian Energy, submission to issues paper, p. 10.

241 Tesla, submission to issues paper, p. 7.

242 AGL, submission to issues paper, p. 7.

243 TasNetworks, submission to issues paper, p. 16.

244 Tesla, submission to issues paper, p. 5.

Both Tesla and TasNetworks suggested that there might be value in undertaking more trials to assess the capability of aggregated distributed energy resources to provide market ancillary services.[245]

7.5.3 Analysis and proposed solution

The Commission has undertaken a preliminary review of the current MASS to assess whether it presents barriers to the provision of market ancillary services from distributed energy resources.

The Commission notes that the MASS was reviewed by AEMO in 2017. This review was undertaken primarily to account for the introduction of the Market Ancillary Service Provider framework. AEMO flagged in the review that there would likely still need to be a broader review of ancillary services in the NEM.[246]

Service provision from aggregators

In the 2017 review, AEMO clarified that the MASS provides for services from aggregators, and that aggregators are able to provide all market ancillary services provided they are able to comply with the MASS. For regulating services, AEMO is able to communicate to the aggregator, who would then be responsible for delivering the required response from the aggregated units in an accurate and timely manner.[247] The MASS also allows for an aggregator to be enabled to provide regulating FCAS, which the aggregator is then able to communicate to its portfolio.

The Commission considers that the current MASS sufficiently enables aggregators to interface with AEMO to provide all market ancillary services. However, as discussed below, there may be other barriers in the MASS that may hinder or prevent an aggregator from actually providing these services.

Measurement and verification of service provision

A number of stakeholders have claimed that there are onerous provisions in the MASS requiring providers of market ancillary services to have high-speed equipment capable of measuring and verifying a response.

The MASS does not actually specify the assets needed to provide market ancillary services. Rather, it outlines the required capability of providers to measure and verify the extent of any service provided. This measurement and verification is expected to occur as close as possible to the connection point(s) of the ancillary service generating unit(s) and load(s). While the MASS does not specify the required metering or equipment, it does require a certain resolution of measurement in order to be able to verify the extent of any service provided. To be able to provide this resolution requires

245 Submissions to issues paper: Tesla, p. 3; TasNetworks, p. 17.

246 AEMO, *Market ancillary service specification review - issues paper*, January 2017.

247 AEMO, *Market ancillary service specification*, July 2017, p. 11.

a certain grade of equipment. To the extent higher resolution of measurement is required, this will likely require more expensive equipment to measure and verify the response.

High speed (50ms) measurement is needed for the provision of fast contingency services under the current MASS. Regulating, slow and delayed services require four-second measurements. Therefore, the more onerous measurement and verification requirements in the MASS are only required to provide the faster services.

AEMO's 2017 review considered the appropriateness of the measurement and verification requirements in the current MASS. In the review, AEMO sought stakeholder feedback on:

- options for accurately determining the extent of a response from aggregated units
- alternatives to the high speed metering requirements
- any other barriers in the MASS to new entrants.

AEMO received nine submissions to its consultation paper.[248] In submissions, stakeholders did not highlight any major technical barriers present in the MASS. Stakeholders also generally supported the need to measure the service being provided on individual sites.

Stakeholders did comment on the onerous nature of the metering requirements in the MASS. Most supported the need for high-speed recording but some queried whether 50ms was the appropriate resolution. ENGIE submitted that 50ms granularity of data measurement may not be necessary for non-synchronous providers.[249] EnerNOC suggested that measuring data at 100ms resolution would not increase measurement errors significantly.[250]

AEMO concluded that the requirement for high-speed recorders did not present a barrier to new entrants. AEMO also concluded that the current arrangements provided some degree of flexibility in terms of arrangements that cater for switched controllers.[251]

While there are challenges associated with capturing high-speed data, the Commission considers that there needs to be further consideration of the trade-off between lower resolution measurements and the extent to which this results in errors in the amount of FCAS enabled. The Commission considers that the current requirement for a resolution of 50ms may be achievable for aggregators of distributed energy resources. In

248 These submissions were received from: Australian Energy Council, AGL, Clean Energy Council, Delta Electricity, EnerNOC, ENGIE, ERM Power, Hydro Tasmania and United Energy. They are available on the MASS review project page.

249 ENGIE, submission to MASS review issues paper, March 2017, p. 2.

250 EnerNOC, submission to MASS review issues paper, March 2017, p. 3.

251 AEMO, *Market ancillary service specification review - draft report and determination*, March 2017.

conversations with stakeholders, the Commission has been made aware of distributed technologies that are able to record data at a 50ms resolution.

The Commission considers the measurement and verification requirements in the MASS for regulating, slow and delayed services are not onerous. Through its own analysis and consultation with stakeholders, it appears to the Commission that measuring and verifying a response at four-second resolution does not pose a barrier to distributed energy resources participating in FCAS markets.

To the extent the Commission is aware, there are no other requirements for high-grade metering imposed through the MASS. To the extent that distributed energy resources are able to verify the provision of services at an appropriate resolution, there does not appear to be other requirements to high-grade metering imposed in the MASS.

The Commission is of the view that it is important that there is an appropriate level of certainty and verification that market ancillary services can and will be provided. These services are required to maintain power system security and may pose a risk to the secure operation of the power system if they are incorrectly provided. The MASS therefore places prescriptive measurement and verification requirements on participants to provide this certainty. Any loosening of these requirements would need to be cognisant of possible adverse impacts on power system security.

However, there may be opportunity to consider whether these requirements will continue to be feasible and appropriate if market ancillary services are increasingly provided by distributed energy resources. As noted by some stakeholders, it may not be practical to test and measure the provision of the service from each individual unit, but there may be ways to do this on a more aggregated or sampled basis.

The Commission therefore considers that there is value in AEMO undertaking trials of distributed energy resources providing market ancillary services. This could provide AEMO and participants with an opportunity to assess the viability of fast FCAS being provided with a lower resolution for measurement and verification, such as 100ms, or ways to test a certain proportion of an aggregator's portfolio and make assumptions about the remainder on that basis. This is discussed more below.

Communication with distributed energy resources for regulating services

The Commission considers that there may be communication issues associated with the participation of distributed energy resources providing regulating FCAS. To the extent that distributed energy resources are unable to receive signals from AEMO within sufficient timeframes, it may limit their ability to providing regulating FCAS.

To dispatch regulating FCAS, AEMO sends an AGC signal to enabled providers to help correct frequency. With large providers, this signal is generally sent directly to the control system for the ancillary service generating unit or load.

To enable regulating FCAS from an aggregator, AEMO would send an AGC signal to the aggregator who would respond to the signal by communicating with the aggregated units to increase or decrease output. This could possibly result in delays between receiving AEMO's AGC signal and the resources providing regulating FCAS. However, the Commission considers that these delays would likely be very minor (under one second) and should not present a significant barrier for distributed energy resources providing regulating FCAS.

Opportunity for market ancillary service trials

In the MASS, AEMO notes that it may allow ancillary service facilities to participate in trials to test the performance of new technologies.

AEMO suggests that any such trials would:

- be for a limited time and quantity
- be subject to conditions including:
  - withdrawing from the market if directed by AEMO
  - using best endeavours to meet the MASS
  - meeting other requirements imposed by AEMO.

The option to undertake trials was an addition made following the most recent review of the MASS in 2017.

The Commission agrees that trials provide a useful opportunity to demonstrate the viability of new technologies in providing market ancillary services. However, the Commission notes that there is limited detail provided by AEMO regarding the technologies or service characteristics that could or would be trialled.

Trialling the provision of market ancillary services from distributed energy resources would provide AEMO with an opportunity to:

- understand the capability of aggregated distributed energy resources to provide system security services
- determine whether the MASS can accommodate these technologies
- assess the viability of different models for communication and verification equipment.

It is also important that information gained through trialling new technologies is shared with relevant stakeholders to improve industry capability and support the development of better regulatory frameworks.

The Commission acknowledges that the option to undertake trials is a relatively recent addition to the MASS. However, there may be value in providing more information to the market regarding the role for trials in FCAS markets. Greater levels of transparency or guidance, where possible, would assist stakeholders in offering to participate in a trial of FCAS from distributed energy resources.

The Commission also notes that, in its *Power system requirements* reference paper, AEMO indicates an interest in working with project proponents where opportunities exist to provide a service from a new technology. AEMO states that the purpose of this would be to ensure that those technologies are subject to a rigorous "innovation funnel" and incorporated into NEM systems in a time frame that permits it to support any emerging shortfalls in the service.[252]

Broader issues with the MASS

As highlighted by Tesla in its submission to the issues paper, there may be broader issues with the MASS and the FCAS verification tool that are currently not appropriately accounting for the ability of certain providers to provide market ancillary services.

The Commission understands that the potential for underestimation of capability relates to:

- the process for registering FCAS capability using the FCAS verification tool
- whether FCAS should value the capacity injected or removed to help correct frequency excursions, or energy provided over set time frames.

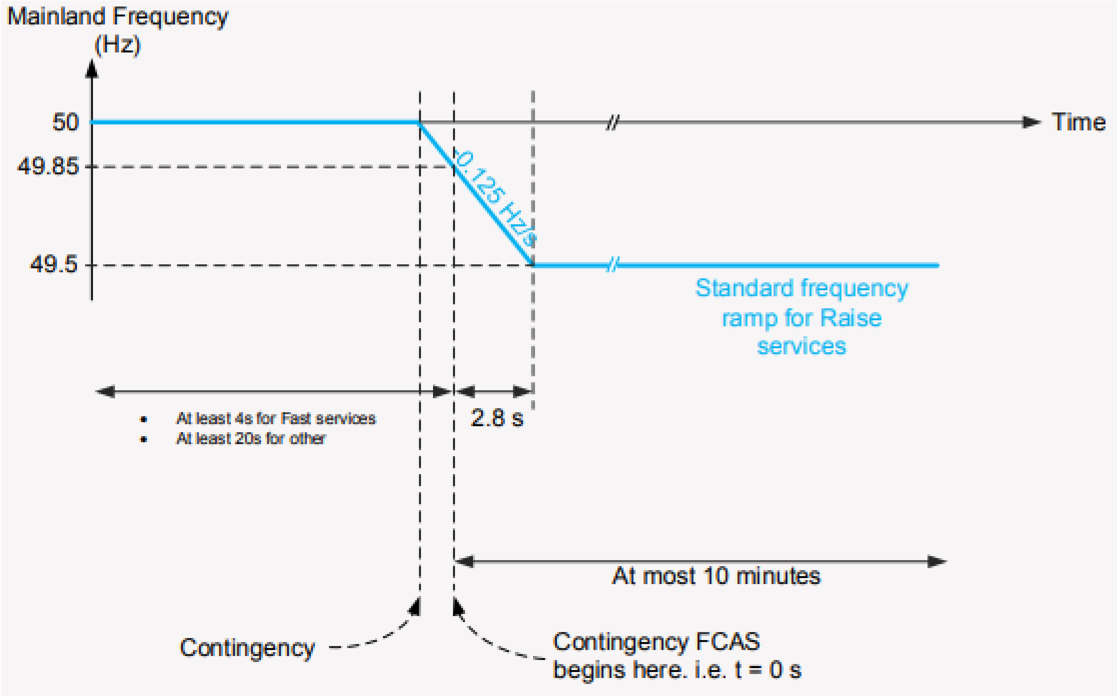
For example, to determine the amount of each contingency raise service a participant can be registered to provide, the MASS and FCAS verification tool currently set out the following:

- A **reference frequency** of 49.5 Hz for the mainland and 48 Hz for Tasmania, which corresponds to the lower range of the normal operating frequency band. This represents the point at which all enabled FCAS should be activated.
- A **frequency dead band** of 49.85-50.15 Hz, which means the range of local frequency through which a variable controller will not operate
- A **frequency ramp rate** of 0.125 Hz per second, which is the assumed rate of change of frequency of the power system following a contingency event.

The combination of these three set points are used to determine the amount of FCAS that a participant could be enabled to provide. This may limit the faster response capable of being provided by technologies such as storage and, as a consequence, sets an enablement level below the installed capacity of these units.

252 AEMO, Power system requirements, reference paper, March 2018, p. 20.

Figure 7.1 Standard frequency ramp for regions other than Tasmania



Source: AEMO, *Market ancillary services specification*, 30 July 2017, p. 29.

The time frames outlined in the MASS reflect the capability of the technologies deployed at the time the FCAS markets were established, together with associated system needs. Providers of contingency FCAS are paid according to the minimum average output in the period either side of the time frame for the service. For example, when providing fast raise services, a provider needs to ramp up within the first six seconds before tapering off over the next 54 seconds. These existing service definitions and associated pricing structures may either not provide very strong incentives for technologies such as fast response batteries or may preclude participation of some emerging technologies.

These issues may exclude newer technologies from being registered to provide their full capability into FCAS markets.

The Commission notes that these issues were considered to an extent through the 2017 review of the MASS. The Commission also notes that a range of other issues were raised throughout AEMO's 2017 review of the MASS, including:[253]

- the difference between a provider's frequency deviation setting[254] and the normal operating frequency band affecting the quantity of FCAS a participant may be able to provide

253 AEMO, *Market ancillary service specification review - draft report and determination*, March 2017, pp. 24-25.

254 The power system frequency at which a FCAS unit using a switched controller should provide FCAS.

- an appropriate methodology for determining the performance of participants providing regulating services
- the interaction between different contingency services
- the potential for units providing regulating services to respond to local frequency measurements rather than the central AGC systems.

AEMO considered those issues to be outside the scope of the 2017 review, but suggested they would be consulted on further through the Ancillary Services Technical Advisory Group.

These issues were subsequently discussed at the Ancillary Services Technical Working Group meeting on 3 May 2017. At the conclusion of the meeting, AEMO agreed to create a roadmap of issues raised in 2017 MASS review so that they are able to be considered at a future date.[255]

The Commission is interested in better understanding these issues in the MASS from participants and AEMO, with the aim of addressing inefficient barriers where they might exist.

The extent to which the current MASS does not fully account for the capability of FCAS from utility-scale storage will likely result in FCAS provided by aggregated storage also being underestimated.

Summary

The Commission has reviewed the MASS and considers there may be some barriers to distributed energy resources providing fast frequency control services. However, the MASS does not appear to impose onerous requirements in regard to the provision of regulating, slow and delayed services. There may be broader issues with the MASS and the valuation of services from new technologies that could impact upon aggregated distributed energy resources.

In its most recent review of the MASS, AEMO provided for the opportunity to trial new technologies. This could be a valuable way to assess the capability for distributed energy resources to provide market ancillary services.

Draft recommendation 5

That AEMO:

(a) provide more information regarding particular service characteristics that may be able to be trialled under the MASS

(b) undertake trials of distributed energy resources providing FCAS that consider various technology types and different options for metering and

255 AEMO, Ancillary Services Technical Working Group, *Meeting minutes*, May 2017.

verification, with a view to sharing the outcomes of the trials with relevant stakeholders

(c) conduct a broader review of the MASS and consider how the value of distributed energy resources can be appropriately recognised.

7.6 Connection arrangements and Australian Standard 4777

This section explores whether the regulatory frameworks under which distributed energy resources connect and operate provide opportunities or barriers for the provision of system security services.

This section outlines:

- issues with the current regulatory frameworks for the connection and operation of distributed energy resources – specifically the connection arrangements and Australian Standard (AS) 4777 that may be inhibiting the participation of distributed energy resources in system security frameworks
- stakeholder views on these issues
- the AEMC's proposed approach to addressing the identified issues.

7.6.1 The issue

To interact with the network, such as through charging or consumption, a distributed energy resource must be connected to the electricity network. To do so, the person who owns the distributed energy resource must enter into a connection agreement with the local distribution network service provider (DNSP).

The connection arrangements set out in the NER establish the obligations and processes by which generating systems and loads connect to a transmission or distribution network. Generally, non-registered participants connect under Chapter 5A of the NER.[256] These rules apply (among others) to:

- retail customers
- micro embedded generators (e.g. retail customers with solar PV or battery storage systems)
- non-registered embedded generators (connecting a system of less than 5 MW but larger than a micro embedded generator).

Chapter 5A does not contain any specific requirements or guidance on the actual technical specifications of connections by retail customers to distribution networks, either with a generating system (such as a solar PV system) or without. Rather, it

256 Non-registered embedded generators may opt to connect under the process outlined in rule 5.3A of the NER. See clause 5A.A.2 of the NER.

contains broad requirements that the terms and conditions of model standing offers or negotiations for connection services must, for example, cover "the safety and technical requirements to be complied with by the retail customer".[257] The exception is that micro-embedded generation is defined in the NER by reference to AS 4777 (discussed below).

This can be contrasted against the arrangements for connections under Chapter 5 of the NER. Chapter 5 covers the connection of registered participants to distribution and transmission networks. When a registered participant connects equipment to the network under Chapter 5, it must register performance standards for that plant that clearly set out the technical capability of the plant.

The performance standards for generating systems cover a range of technical capabilities, including reactive power capability, quality of electricity, response to frequency and voltage disturbances during and following contingency events, frequency control, protection systems, and monitoring and control systems. This provides parties connecting under Chapter 5 with a transparent process for establishing the technical requirements of that connection. These performance standards assist AEMO in maintaining the power system in a safe and secure operating state, as well as assisting network service providers in meeting their obligations under the NER.

As set out above, there are no detailed technical requirements in the NER for the connection or operation of distributed energy resources that connect under Chapter 5A.

Individual DNSP connection arrangements

As the NER is not highly prescriptive regarding the technical aspects of connections under Chapter 5A, a significant amount of discretion on the technical requirements of a distributed energy resource lies with the DNSP. The rapid, and often concentrated, uptake of distributed energy resources has resulted in some DNSPs requiring distributed energy resources to meet certain technical requirements. However, the AEMC understands that these requirements are not consistent between DNSPs and have led to different approaches to distributed energy resources depending on the location of their connection. This issue was discussed further in the final report of the AEMC's *Distribution market model* project.[258]

The Queensland DNSPs have developed a joint connection standard containing detailed technical requirements and performance standards to "provide proponents of micro embedded generating units information about their obligations for connection to and interfacing with the Ergon Energy or Energex networks".[259] This was driven by very high uptake of residential PV in south-east Queensland. These standards place

257 See clause 5A.B.2(b)(4) of the NER.

258 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

259 See: https://www.ergon.com.au/__data/assets/pdf_file/0005/198698/STNW1170-Connection-Standa

certain obligations on distributed energy resources connected to these networks that assist with maintaining the distribution network within its technical limits. This includes assisting with voltage control and relieving thermal constraints.

For small-scale generation (rated less than 30kVA), the connection standard outlines a range of inverter settings that the inverter must be able to operate within, and the set points at which the inverter must trip.[260] It requires inverters to provide reactive power support to the network by either operating at a fixed power factor (0.9 lagging) or to vary power factor with network voltages. The connection standard requires the inverter export limits and over-voltage trip settings to meet the DNSP's requirements.

Although not mandatory for all connections to Ergon and Energex's networks, some inverters may be required to be able to have various operational modes. These modes are:

- disconnect
- do not consume power
- increase consumption
- do not generate power
- increase power generation.

These services are not necessarily required by Ergon/Energex for power system security purposes. Instead, they assist Ergon/Energex in maintaining distribution equipment safely within voltage and thermal limits. However, these functions could be used to maintain power system security.

Australian Standard 4777

Australian standard (AS) 4777 applies to low voltage inverters connected to the power system.[261] This applies to grid-connected PV inverters and inverters for energy storage systems, i.e. batteries. Australian standards are non-binding unless enforced through a contract or separate piece of legislation. The term micro-embedded generator is defined in the NER with reference to the standard and several DNSPs, including Ausgrid, Energex and Ergon Energy, refer to AS 4777 in their connection arrangements for small-scale embedded generation.

Impact of connection arrangements and AS 4777

The technical requirements imposed through these frameworks may result in distributed energy resources having the capability to provide system security services,

260 Residential solar PV and batteries need to be coupled with an inverter. This inverter converts DC power - the form of power that is output by batteries and solar PV - to AC power which is used throughout a home and can be exported into the power grid.

such as an increase in power in response to a drop in frequency, or voltage support. AS 4777 requires inverter-connected energy systems to have the ability to be remotely controlled. As a result, the standard may enable the capability of large amounts of distributed energy resources to be aggregated to provide system security services such as frequency control or voltage support.

However, the connection arrangements in the NER, AS 4777 and DNSPs' own connection requirements do not appear to value or incentivise the provision of system security services by means of distributed energy resources. Instead, these frameworks appear to be in place largely to enable DNSPs to manage local network issues, such as network voltages.

Distributed energy resources do not appear to be compensated for the provision of such services. It may also be the case that DNSPs, through their connection arrangements, have sole access to services that can be provided by distributed energy resources. While DNSPs may require certain services to be provided by distributed energy resources to maintain the safe and secure operation of their networks, this may compromise or limit distributed energy resources' ability to provide services to other parties, including AEMO as the body responsible for managing power system security.

Further, some of the mandatory requirements in AS 4777 may impede the ability of distributed energy resources to participate in the provision of system security services. For example, limits to ramp rates for distributed energy resources may restrict their ability to provide frequency control services.

To date, distributed energy resources have had a limited role in providing system security services. If this were to change, the obligations imposed through the NER connection arrangements and AS 4777 may hinder increased participation.

7.6.2 Stakeholder views

In submissions to the issues paper, a number of stakeholders highlighted the connection arrangements for distributed energy resources as a barrier to the provision of system security services.

Tesla submitted that the connection approval processes and metering arrangements should be different and appropriate for the size of the installation being connected.[262] TasNetworks agreed that consistency between large and small generators should be applied at a policy level, but noted that attempting to apply the specific technical requirements in the NER for distributed energy resources will most likely not work in practice.[263] Energy Queensland shared a similar view.[264] Origin Energy submitted

261 The standard applies to inverters up to 200kVA connected to low voltage parts of the grid.

262 Tesla, submission to issues paper, p. 7.

263 TasNetworks, submission to issues paper, pp. 16-17.

264 Energy Queensland, submission to issues paper, p. 10.

that applying a large generator connection framework to small scale distributed energy resources would be costly and time consuming for little benefit.[265]

S&C Electric Company noted the disparity between the connection arrangements for large scale generators and distributed energy resources. It noted that network charges do not reflect the costs that distributed energy resources could impose.[266]

TasNetworks and Energy Networks Australia submitted that the connections framework for distributed energy resources has, to date, focussed on addressing DNSP issues. Both noted that this may limit the ability for an aggregator to utilise the flexibility of the inverter fleet to provide network support or system security services.[267] Energy Networks Australia submitted that the technical standards that apply to the connection of distributed energy resources have been focused on managing local network issues as leaving these issues unresolved would pose barriers to connection.[268] Meridian Energy was of the view that there are difficulties for distributed energy resources to participate in the market due to the "the friction associated with excessive requirements from distributors, which are out of balance with the associated consequences".[269]

Tesla also submitted that the lack of consistency in the interpretation of AS 4777.2 and Chapter 5A of the NER results in inconsistent opportunities for distributed energy resources between networks.[270] It suggested that increasing consistency between jurisdictions would be a valuable step in facilitating the participation of distributed energy resources.[271] Energy Networks Australia submitted that the increase in distributed energy related connections have driven the need for standards to be applied, including AS 4777. Energy Networks Australia suggested that the AEMC consider working with Standards Australia to facilitate a further review of relevant aspects of Australian Standard 4777. It submitted that the standard has a number of features that should be considered further if distributed energy resources are to be integrated into system security frameworks.[272]

Origin Energy supported the development of nationally consistent guidelines for the connection of distributed energy resources but was cautious that an Energy Network Australia led project would favour network issues.[273]

EnergyAustralia submitted that the total costs of imposing higher connection standards should be weighed up against the cost of system-wide solutions to issues

265 Origin Energy, submission to issues paper, p. 3.

266 S&C Electric Company, submission to issues paper, p. 14.

267 Submissions to issues paper: TasNetworks, p. 16; Energy Networks Australia, p. 3.

268 Energy Networks Australia, submission to issues paper, p. 3.

269 Meridian Energy, submission to issues paper, p. 10.

270 Tesla, submission to issues paper, p. 8.

271 Ibid, p. 7.

272 Energy Networks Australia, submission to issues paper, p. 5.

273 Origin Energy, submission to issues paper, p. 3.

caused by non-standardised distributed energy resource installations.[274] Pacific Hydro suggested that distributed energy resources need to have well defined connection standards to ensure that they support the power system in the local area.[275]

7.6.3 Analysis and proposed solution

As noted in stakeholder submissions, the issues associated with connections to the distribution network predominantly relate to:

- inconsistent connection arrangements between jurisdictions
- overly onerous technical requirements being imposed on distributed energy resources
- lack of transparency regarding the application of AS 4777
- a perception of imbalance that favours the DNSP when making a trade-off between mandating services and allowing distributed energy resources to provide services.

The Commission considers that the existing connection frameworks in Chapter 5A of the NER and AS 4777 may limit the ability for distributed energy resources to participate in system security frameworks.

Connection frameworks

The Commission is of the view that the connection framework for distributed energy resources should provide a balance between:

- accommodating the need for the DNSP to meet its service obligations
- permitting timely connections of distributed energy resources
- allowing owners of distributed energy resources to maximise the value of their assets by providing services to other parties.

In order to connect distributed energy resources to the network without adversely affecting power system security or preventing the ability for the DNSP to meet its service requirements, some technical requirements are necessary.

In the Commission's view, the efficient uptake of distributed energy resources is supported when these technical requirements are clear, proportionate and relevant to what is being connected and how it will be operated. Overly onerous technical requirements are likely to increase the costs of connection and limit the range of services that could be provided competitively, such as FCAS, which may deter consumers from installing distributed energy resources, or incentivise them to find

274 EnergyAustralia, submission to issues paper, p. 5.

275 Pacific Hydro, submission to issues paper, p. 14.

ways to install distributed energy resources without approval from the DNSP. On the other hand, technical requirements that are too low have the potential to create or exacerbate the technical impacts of distributed energy resources on distribution networks.

In the issues paper, the Commission considered whether there was value in harmonising connection arrangements between Chapter 5 and Chapter 5A. As set out above, a greater level of technical prescription applies to generators who connect under Chapter 5 than those that connect under Chapter 5A. Introducing more technical prescription in Chapter 5A of the NER would make the framework for connecting distributed energy resources more consistent between distribution networks, and across the distribution and transmission networks. However, as noted by stakeholders, doing so may impose material new costs and delays, and may fail to accommodate the different technical characteristics of each distribution network in the NEM. The Commission therefore considers that it would not be efficient to apply prescriptive technical requirements for the connection of distributed energy resources in Chapter 5A of the NER.

Rather, the Commission is of the view that these requirements should be set by DNSPs in a manner that provides transparency and justification for these requirements. It is important that DNSPs have the discretion in the connection process to address risks to the security and safety of the power system. The connection arrangements should also not preclude the efficient co-optimisation of the value of the many services that distributed energy resources are capable of providing, including services to wholesale markets (e.g. FCAS) and services to the network business itself (e.g. voltage control).

The Commission also considers that there should be greater consistency between networks to reduce transaction costs for parties connecting, operating and aggregating distributed energy resources. A lack of consistent technical requirements across and within network areas, or a lack of transparency regarding the reasons why different technical requirements are being imposed, can increase the transaction costs of connecting distributed energy resources. Having bespoke and inconsistent connection frameworks would also be likely to increase the transaction costs for aggregators due to the potentially unclear and varying obligations imposed on distributed energy resources.

Energy Networks Australia is currently undertaking a review of DNSP connection arrangements.[276] The review is being undertaken following on from recommendations made in the Energy Networks Australia/CSIRO *Electricity network transformation roadmap*, and the Finkel review. The Commission supports this work and is on its steering committee. The project provides an opportunity to address the concerns raised by stakeholders in their submissions to the issues paper, and to consider whether the new guidelines will enable distributed energy resources to provide system security services.

276 For more information see: http://www.energynetworks.com.au/sites/default/files/13122017_plug_and_play_on_the_way_for_renewable_connections_mr_0.pdf

Draft recommendation 6

That Energy Networks Australia, in developing its national connection guidelines, provide guidance on:

- what capability is reasonable to require from distributed energy resources as a condition of connection in order to address the impact of that connection
- the expected application of AS 4777 to different connection types and sizes
- the technical justification for any mandated services
- the extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services.

The Commission encourages stakeholders to provide input into the development of these guidelines.

The broader arrangements for distribution network access and connection for distributed energy resources are being considered in the Commission's 2018 *Economic regulatory framework review*.[277]

Australian Standard 4777

As noted in the issues paper, the Commission is of the view that the application of AS 4777 has the potential to limit the ability for distributed energy resources to provide system security services. Mandating the provision of certain services from distributed energy resources through AS 4777 may constrain the future ability for those resources to offer system security services.

This was noted by AEMO in its 2017 review of the market ancillary service specification. In the review AEMO noted that it would be inappropriate for services mandated through DNSPs' application of AS 4777 to be aggregated and offered to the market.[278]

While the use of all Australian standards is voluntary, they can be (and are often) called up into regulation or contracts. Many of the features in AS 4777 are not imposed by default but can be made mandatory through DNSPs’ connection arrangements. As such, standards can have a significant impact on consumer decisions about which products and services to buy, and how those products and services can be used. The Commission is of the view that, where distributed energy resources are mandated to

---

277 See: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1

278 AEMO, *Market ancillary service specification*, issues paper p. 18.

provide services to the DNSP and broader network, the services should be proportionate to local network needs.

The Commission supports the development of standards that define minimum safety and technical requirements for the operation of micro-embedded generators and their connection to the electricity network. However, any standard that unnecessarily precludes the appropriate valuation of the multiple value streams that distributed energy resources can provide, including through the provision of system security services, will affect the development of a competitive market for distributed energy resources.

The development of Australian standards is overseen by Standards Australia, a non-government, not-for-profit organisation. Standards Australia forms technical committees of relevant stakeholders to develop standards through a process of consensus. The AEMC has no direct involvement in the development of standards. This draft report therefore does not propose any reviews or changes to existing standards.

Nevertheless, as AS 4777 is directly referenced in the NER and certain other standards can be called up into DNSPs' connection arrangements, the Commission encourages committee members and others involved in the standards development process to have regard to the potential for distributed energy resources to provide system security services when developing and commenting on standards.

7.7 Technical impacts of distributed energy resources providing system security services

Distributed energy resources providing system security services would have a multifaceted relationship with local network conditions. Local network conditions must be such that system security services can physically be provided. Conversely, the provision of system security services should not cause the power system to become insecure, or prevent the DNSP from being able to meet its service obligations.

This section outlines:

- the AEMC's views on issues associated with distributed energy resources providing system security services
- stakeholder views on these issues
- the AEMC's analysis and proposed approach to addressing the identified issues.

7.7.1 The issue

This review is not specifically considering system security issues associated with the increasing uptake of distributed energy resources. However, in having distributed energy resources providing system security services, there is the need to consider any new issues introduced alongside this service provision.

There are two main concerns that have been raised:

- local network conditions would affect the ability for distributed energy resources to provide system security services
- distributed energy resources providing system security services are likely to have an impact on local network conditions.

7.7.2 Stakeholder views

In its submission to the issues paper, AGL noted that local voltage issues may constrain the ability for distributed energy resources to provide system security services.[279]

Energy Networks Australia suggested that any changes to the connection arrangements for distributed energy resources should maintain consideration of the distribution network.[280] TasNetworks noted that questions still remain in regard to the ability of inverters to remain connected immediately following significant network disturbances.[281]

7.7.3 Analysis and proposed solution

If distributed energy resources are to provide system security services, there will need to be further consideration of associated technical issues.

Impact on ability to provide services

To provide services to the network, including energy or ancillary services, the network must be technically capable of supporting the provision of the services. This is primarily contingent on there being sufficient network voltage and sufficient thermal capacity.

FCAS provided by transmission-connected generators have generally been provided into strong, high-voltage networks. Grid voltages are widely monitored and maintained to a range that is necessary to maintain power system security. Transmission networks have been designed to facilitate large amounts of power being injected and withdrawn.[282] To the extent that the grid might not have spare thermal capacity, this can be managed through network constraints.

The ability for distributed energy resources to provide system security services depends on local conditions. At a distribution network level, network conditions tend to be more variable and less closely monitored than at the transmission network level.

---

279 AGL, submission to issues paper, p. 7.

280 Energy Networks Australia, submission to issues paper, p. 3.

281 TasNetworks, submission to issues paper, p. 16.

282 In areas of the grid where there are lower levels of system strength, grid voltages would vary more for a change in power or load.

This is partially because of the substantial costs associated with granular monitoring and control within the distribution network. It is also because a high level of monitoring was generally not necessary in distribution networks prior to the substantial uptake of distributed energy resources and energy intensive loads such as air conditioners. Consequently, DNSPs do not monitor network voltages at individual connection points. Distribution networks also do not have network constraints to manage power flows.

As a result, providing system security services from within a distribution network may be more complex than providing services into the transmission network. Variations in network voltages would affect the ability of inverter-connected distributed energy resources (including solar PV and batteries) from inputting energy. If not properly managed, the coordinated output of distributed energy resources for the purpose of providing system security services may impinge the thermal limits of distribution equipment.

Responsibility for addressing these issues may be best left to the aggregator. By developing more complex communications and control systems, an aggregator should be able to monitor the capability of its portfolio by assessing both the individual units, as well as local network conditions. An aggregator may be able to offer a geographically diverse provision of market ancillary services to minimise the impact of system disturbances. However, this may also require greater levels of communication from DNSPs on system voltages and thermal capacity, as well as other technical issues.

It is worth noting that issues within a distribution network, such as voltage control and thermal constraints, may also be able to be resolved by distributed energy resources themselves. As set out above, the AEMC envisages a future where DNSPs set the minimum operational parameters of their networks, but services from distributed energy resources, among other technologies, can be procured on a competitive basis to address more dynamic system needs such as congestion.

Impact of provided services

In addition to network conditions being conducive to the provision of system security services, the services themselves should not cause the power system to become less secure or prevent the DNSP from meeting its service obligations.

A raise frequency service (an increase in generation or a decrease in load) would also have the effect of increasing voltage local to the provision of the service. Conversely, a lower frequency service (a decrease in generation or an increase in load) would lower the local voltage.

At the transmission network level, the grid has generally been able to absorb the power injection and maintain voltages. The transmission network has been designed to handle large increases in power being injected or withdrawn. The distribution network on the other hand was not designed to facilitate large amounts of local generation and rapid shifts in supply/demand (such as a contingency frequency response).

This issue relates to connection arrangements for distributed energy resources discussed in section 7.6. Many of the requirements imposed through DNSP connection arrangements and AS 4777 aim to mitigate adverse network impacts caused by distributed energy resources. For this reason, Energy Network Australia's development of national connection guidelines should provide clarity on how distributed energy resources impact on network voltage, and on how thermal limits can be addressed while also providing for the opportunity for distributed energy resources to provide services to address these local issues, as well as broader system security issues.

The need for more information about the technical characteristics of distribution networks is not a new consideration. The AREMI map, developed by CSIRO’s Data61 in partnership with ARENA, Geoscience Australia and the Clean Energy Council, includes data sets produced by the Institute of Sustainable Futures on areas of network constraint, planned investment and the potential value of distributed energy resources in networks across the NEM.[283] While there are caveats around the accuracy and completeness of the data, such information is a valuable means to help a range of parties better understand the characteristics of the networks in which they are investing and operating. It may also help to incentivise consumers to locate and operate in the 'right' areas, for example areas where distributed energy resources can be used to help alleviate network constraints.

Conclusion

The provision of system security services from distributed energy resources involves complex technical issues. Parts of distribution networks may have limited capability to monitor local conditions and accommodate system security services. While the increasing uptake of distributed energy resources poses a challenge to distribution networks, they also provide an opportunity for the DNSP to utilise these technologies to monitor and maintain network conditions to appropriate levels.

The extent to which distributed energy resources are able to assist with maintaining the secure operation of networks is influenced by:

- the level of dynamic information about congestion and technical issues provided by network businesses
- price signals to distributed energy resources to address these congestion and technical issues.

AEMO, DNSPs and distributed energy resource aggregators should share information that would enable distributed energy resources to participate in the provision of system security services without compromising the safe, secure and reliable operation of the power system. Undertaking trials of distributed energy resources providing system security services may provide a valuable avenue for understanding the

283 See: https://arena.gov.au/project/aremi-project/

interactions between these services being provided, and the technical impacts on the network.

Draft recommendation 7

That:

(a) AEMO, in conjunction with DNSPs, conduct trials of aggregated distributed energy resources providing FCAS to assess their ability to provide services under different network conditions, and how the provision of those services affect the local network and the power system more broadly

(b) DNSPs and aggregators share information about the types of network conditions that may constrain the operation of distributed energy resources providing system security services, and the types of services that may affect network conditions, with a view to determining how the value of distributed energy resources can be maximised for both parties.

8 Future FCAS frameworks

In this draft report, the Commission has proposed a number of changes to the existing frequency control frameworks. These changes are primarily aimed at addressing the recent deterioration in frequency performance under normal operating conditions and to improve the general transparency and simplicity of current arrangements.

However, the Commission also recognises that the gradual shift towards more non-synchronous and variable sources of electricity generation and consumption is expected to continue, and that difficulties in predicting this variability are likely to increase the potential for imbalances between supply and demand that can cause frequency disturbances.

As this shift in generation technology continues, there is likely to be a growing need to re-evaluate the current design of frameworks for frequency control services. New approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies.

Changes to these frameworks are likely to involve their own set of costs, both in terms of implementation but also in the means by which frequency control services are procured. Furthermore, some technologies that provide frequency control services also have the potential to provide other system supporting services, such as system strength, and so frameworks designed for frequency control must also consider the implications for these services.

This chapter sets out the Commission's considerations with respect to whether or not broader changes may be needed to the existing frequency control frameworks.

- Section 8.1 sets out the means by which the existing frameworks for frequency control services may not keep pace with the shift in generation technologies to efficiently deliver the outcomes needed to support system security.
- Section 8.2 discusses the time frames over which changes to existing frameworks are likely to be needed to maintain effective and efficient control of system frequency.
- Section 8.3 sets out a spectrum of possible alternatives to or enhancements of existing FCAS frameworks that could be implemented to achieve the required frequency performance.
- Section 8.4 provides a more detailed description of each of the alternatives on the spectrum.
- Section 8.5 explores the ability of each of the alternatives on the spectrum to address the drivers of change identified in chapter 3.

- Section 8.6 discusses the costs and benefits of adopting such alternatives and identifies a number of potential changes that could be made within the existing arrangements.

The Commission welcomes stakeholder comments on its approach to future FCAS frameworks, including the structure of its categorisation of frameworks on a spectrum from direct (centralised) control of the provision of frequency control services through to fully distributed (decentralised) control.

8.1 Potential future deficiencies of the existing frequency control frameworks

The existing design of regulating and contingency FCAS markets has proved effective in optimising the dispatch of FCAS sources in real time to provide efficient market outcomes. However, as set out in chapter 3, there are a number of drivers of change in the current market environment, which at some point in the future may limit the ability of FCAS markets to continue to deliver efficient market outcomes in the interests of consumers.

In particular, existing frameworks, as they are currently applied, may be inadequate in addressing the future needs of the power system, as:

- they do not place an explicit value on the provision of fast frequency response (FFR) services or inertia, and do not coordinate with the provision of other system services, such as system strength
- current definitions of contingency services (6 sec, 60 sec, 5 min) are based on the response characteristics of conventional technologies in the NEM, which may present barriers to the provision of response from newer technologies e.g. synthetic inertia from wind
- while they have proven effective in optimising efficient dispatch of FCAS sources in real time they may be less effective in providing longer-term investment certainty due to a lack of contracting (ie the lack of counterparties who are willing to hedge the risks existing in FCAS markets), which could be particularly problematic for storage technologies
- they do not provide incentives on market participants to reduce their potential impact on the need for frequency control services e.g. variability in generating output over time or capacity of generating units and associated impacts on credible contingency size.

These issues are discussed in more detail below.

8.1.1 Lack of ability to value inertia and FFR and coordinate with other system services

The ability of the power system to resist large changes in frequency arising from the loss of a generator, transmission line or large industrial load is initially determined by the inertia of the power system. Since the commencement of the NEM, the dominant generating technologies have been high inertia steam turbines, hydro and combined cycle gas turbines. These generating technologies still represent over 80 per cent of the current installed capacity in the NEM. However, as discussed in Chapter 3, a significant share of this capacity will be progressively age retired over coming decades, reducing levels of inertia in the power system. Many of the new generating units connecting in the NEM are non-synchronous generating technologies that operate through inverters and as such do not provide real inertia. As the generation mix shifts to smaller and more non-synchronous generation, inertia may not be provided as a matter of course giving rise to increasing challenges for AEMO in maintaining the power system in a secure operating state.

New technologies, such as wind farms and batteries, offer the potential for frequency response services that act much faster than traditional frequency control services, perhaps as quickly as a few hundred milliseconds. However, even this small time delay of FFR technologies therefore implies that there is a level of inertia that must be online at any point in time to resist frequency changes at the time of any contingency event as well as over the first few hundred milliseconds following a contingency event. Beyond this initial time period, FFR technologies have the potential to be used in combination with inertia to stabilise system frequency.

The current FCAS markets were designed to reflect the inherent technical characteristics of the existing generation fleet. This included an assumption that the system would have significant inertia at all times and that the expected rate of change of frequency after a disturbance would be low and able to be managed with relatively slow response services. The relative abundance of inertia in the power system suggested that there was no need to separately value this technical characteristic of generators.

In the future, these assumptions will not necessarily hold as greater levels of generation is non-synchronously connected to the grid impacting on the level of inertia in the system at any point in time and increasing the rate of change of frequency after any system disturbance. It is expected that the value of system inertia and of FFR will increase over time. As such, these services should be transparently valued within the FCAS frameworks to ensure that investment decisions in new generation and storage assets reflect the value to the NEM of these and any other desirable characteristics. Failure to do so may see investments occur that are not optimised to potentially provide these valuable services.

At present, levels of inertia across the NEM are still relatively high and the typical levels of inertia provided by generators at any point in time is sufficient to withstand the occurrence of the largest credible contingency. As such, the initial instances of insufficient inertia will likely arise from a separation contingency event which results in the islanding of an area of the transmission network.

Under these circumstances, the level of inertia that is required to maintain the RoCoF to a given limit can be divided into two components:

1. **Minimum level of inertia** – The minimum level of inertia that is required to maintain an islanded system in a satisfactory operating state represents a lower bound on the level of inertia that is required to feasibly operate the system

2. **Market benefits** – Additional inertia above the minimum level of inertia would allow for a more unconstrained operation of the islanded system or additional interconnector flows when not islanded. This would provide benefits of improved reliability and a lower overall cost of energy provision by alleviating constraints on the system.

On the 19 September 2017, the Commission made a final rule relating to *Managing the rate of change of power system frequency* rule change request.[284] The final rule places an obligation on TNSPs to procure minimum levels of inertia or procure other services such as frequency control services that reduce the minimum level of inertia required.

The final rule provides a high degree of confidence that system security can be maintained when separation and islanding of sub-networks occurs. However, beyond the minimum levels of inertia required to maintain the system in a secure operating state, a market mechanism for inertia could facilitate the efficient provision of additional inertia in order to maximise market benefits.

Going forward, new technologies that have the potential to provide new, faster frequency control services will become increasingly important as a complement to, and partial substitute for, inertia. Any changes to the design of FCAS markets should consider how FFR services might be incorporated, and long-term options to facilitate co-optimisation between frequency control ancillary services and inertia.

The Commission's analysis also suggests that further consideration needs to be given as to how inertia can be accurately valued with the application of constraints to manage other system security requirements, such as system strength and system stability. Changes to frequency control frameworks will need to consider impacts on system security constraints on the system as a whole.

8.1.2 Impact of current service definitions

Existing definitions of frequency control services may restrict the types of technologies that can provide a frequency response.

284 See: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

Current definitions of contingency services are based on the response characteristics of conventional technologies in the NEM, which may present barriers to the provision of response from newer technologies e.g. synthetic inertia from wind.

The arrangements for ancillary services in the NEM are set out under section 3.11 of the NER. Specifically, clause 3.11.2 lists the six contingency services comprising fast, slow and delayed for both raise and lower responses. The specification of each of these services is provided in AEMO's market ancillary services specification (MASS).[285] The MASS currently defines:

- the fast service as a six second service
- the slow service as a sixty second service
- the delayed service as a five minute service.

The time frames outlined in the MASS reflect the response characteristics of the technologies deployed at the time the FCAS markets were established. The response characteristics of a steam turbine would fit within the time frames for the fast six-second service, hydro turbines provide a slower response that is more suited to the slow sixty-second service, and gas turbines suit the delayed five-minute service when they are required to start up post contingency.

Of course, individual units are likely to be able to provide more than one service. For example, a high inertia steam turbine providing base load generation may readily survive an initial credible contingency event and then respond by opening steam valves to gain an immediate active power increase. This response could then be followed by increased fuel injection to raise boiler pressure and provide a more prolonged increase in active power.

An important design characteristic of FCAS in the NEM is that participants in FCAS markets are paid for enabling the service in any dispatch interval in which they receive an enablement instruction with the price received expressed in $/MW. The calculation of the volume of service (MW) available from any generator is based on the actual energy estimated to be able to be injected over the measurement timeframe. That is, it is the sum of all the energy provided across the time frame of the service. For example, for the six second service, the MASS defines this in terms of the lesser of twice the time average of the response between zero and six seconds and between six and sixty seconds.

These existing service definitions and associated pricing structures have proven effective to date in optimising the provision of contingency services from conventional generating technologies.

However, existing service definitions may restrict the types of technologies that can participate and the current approach to pricing services may not adequately reflect the value associated with the specific capabilities of different technologies. There are a

285 AEMO, Market Ancillary Service Specification, 30 June 2017, p. 11.

variety of different technologies that have the potential to provide a FFR contingency service to manage sudden changes in system frequency. Each of these technologies may provide these services with distinct operational characteristics, including whether the service is capable of rapidly injecting as well as withdrawing active power, whether the service is capable of sustaining the delivery of active power over a period of time, and the specific profile of the power injection in response to the frequency change.

An example is synthetic inertia from wind farms, which is capable of delivering a rapid injection of active power but is unable to sustain the response for a long period of time. This technology may be substantially undervalued under the existing service definitions, despite the potential significant value provided from a much more rapid initial response.

Some stakeholders have also noted issues with the current design of the FCAS verification tool,[286] which AEMO uses to define the frequency response profile upon which new connecting providers will be remunerated. Tesla suggests that the FCAS verification tool underestimates the capability of inverter-based fast responding technologies because it has been developed in accordance with the response characteristics of synchronous generators[287] This issue was discussed in section 7.5.3 in relation to distributed energy resources.

In the long run, continued reliance on historically determined service definitions may significantly reduce the pool of potential FCAS suppliers as the generation mix changes resulting in an increased risk that the current FCAS frameworks will no longer be effective.

8.1.3 Lack of contracting to support investment certainty

The current FCAS frameworks parallel the wholesale energy market in that generator bids are ranked in order of price with all participants receiving the same price consistent with the marginal generator offer. Given a workably competitive market, this approach achieves efficient prices that reflect all available information prior to the five-minute dispatch interval. As such, these frameworks are effective in optimising efficient dispatch of FCAS sources in real time. The design and operation of the existing FCAS markets is described in section 2.1.2.

The optimisation process of FCAS frameworks has been sufficient to date in achieving efficient outcomes because the existing fleet of generators have tended to provide

286 AEMO publishes an FCAS verification tool to help participants calculate the level of FCAS that can be delivered by their plant in accordance with the principles in the market ancillary services specification. This verification tool does not form part of the market ancillary services specification but contains algorithms that are used by AEMO to verify the contingency services provided by a market ancillary service facility. Participants are required to nominate the quantity of FCAS that they are able to provide into each FCAS market. To be registered and subsequently enabled to provide that FCAS, AEMO needs to determine that the participant is capable of providing these quantities. Participants are able to use the FCAS verification tool to calculate the amount of FCAS they would like AEMO to be able to enable them for in each FCAS market.

287 Tesla, Submission on issues paper, 5 December 2017, p. 5.

FCAS as a by-product of energy production. FCAS has generally been supplied from assets constructed and primarily aimed at participating in the wholesale energy market. As such, potential revenue from participating in FCAS markets was unlikely to have been a significant factor in justifying the initial investment for the majority of the incumbent generators.

However, as conventional generators retire, and newer technologies take their place, there is likely to be a greater focus on FCAS income as a bankable revenue stream. In this case, the current market framework may not be ideal in that it does not readily facilitate secondary contracting[288] of the kind used by wholesale electricity market participants to create revenue certainty and underwrite investments. This may be largely due to the arrangements though which FCAS costs are recovered, which tend to smear the costs across multiple market participants, but may also be due to the historically low costs of FCAS relative to the size of the overall energy market.

A number of technologies are capable of providing a fast frequency response. AEMO notes that these technologies have the potential to be more valuable to the power system than as just a substitute for synchronous inertia.[289] This is because FFR can help to return the power system to the correct frequency rather than simply slowing the rate of change of frequency following a disturbance. Such technologies may face barriers to participation with the limited revenue certainty provided by existing FCAS frameworks.

Under the final rule made by the Commission in relation to the *Managing the rate of change of power system frequency* rule change request, transmission network service providers may enter into contractual arrangements with providers of fast frequency response services as a means of meeting their obligation to maintain minimum levels of inertia.[290] These contractual arrangements would provide some level of revenue certainty to those providers of frequency control services, albeit limited to the minimum level of inertia that is required.

8.1.4 Lack of incentives to reduce the requirement for frequency control services

The current cost recovery arrangements for contingency services do not provide incentives on market participants to reduce their potential impact on the need for frequency control services. This lack of alignment of causation and cost recovery undermines any price signals that might impact on investment or operational decisions that would minimise the need for contingency FCAS.

Currently, AEMO determines the level of contingency FCAS based on the impact of the single largest contingency event, such as the unexpected disconnection of one

288 In the wholesale electricity market, participants enter into contracts with each other to manage their financial exposure to the spot price. The use of the term 'secondary' reflects that these contracts are voluntarily entered into by participants outside the regulated structure of the spot market.

289 AEMO, *Power system requirements – reference paper*, March 2018, p. 15.

290 AEMC, *Managing the rate of change of power system frequency - final determination*, 19 September 2017.

operating generating unit or one major item of transmission infrastructure.[291] Under the current arrangements, it is possible that a single large generator (or transmission element) could represent a maximum contingency size that is substantially greater than the next largest potential credible contingency. This creates a need to procure additional contingency services solely for the purposes of managing the potential impacts to system frequency from the sudden disconnection of one specific generating unit or transmission element. For example, there would be a 50 per cent increase in the volume of contingency FCAS required where the largest generating unit is dispatched at 750 MW and the next largest unit is dispatched at 500 MW.[292] However, despite the substantially greater levels of contingency FCAS required, the larger generating unit setting the FCAS MW requirement pays the same in $/MWh terms as all other market participants.

Under the current contingency FCAS market frameworks, the costs associated with sourcing contingency FCAS are recovered in proportion to market participant energy consumption or generation. The costs of raise services are recovered from generators and the costs of lower services are recovered from market customers.

Historically, these cost recovery arrangements have been sufficient as the majority of generating units have been synchronous steam turbines of a similar installed capacity. However, many newer types of generating technologies have much smaller installed capacity, and so as the generation mix changes over time, the FCAS cost implications for the connection of a new large generating unit may become more pronounced and potentially result in the procurement of large volumes of contingency FCAS to cater for a small number of potential contingencies.

8.2 Time frames for possible broader changes to the design of FCAS frameworks

In chapters 5 and 6 of this draft report, the Commission has set out proposals for changes to FCAS frameworks in some immediate priority areas, including the creation of incentives for the provision of a primary regulating response, improvements in the transparency and simplicity of cost recovery arrangements, and increased monitoring and reporting of frequency performance. The Commission considers it important for these changes to frequency control in the normal operating frequency band to be implemented in the short term in order to improve the recently observed deterioration in frequency performance.

The Commission also considers that further substantive changes to FCAS frameworks may be required over time to address the deficiencies set out in section 7.1 in relation to the appropriate valuation of inertia and FFR services, and the participation of emerging technologies in the provision of frequency response services. However, the Commission considers that, in order to determine the appropriate timeframes for

291 Clause 4.2.3(b) of the NER.

292 The additional level of FCAS enabled by AEMO would be less than 50 per cent due to the impacts of load relief.

making substantive changes to FCAS frameworks, it is necessary to identify when and in what format these deficiencies are likely to become material.

8.2.1 Time frames for incorporation of inertia and FFR services

As discussed in section 8.1.1, the initial instances of insufficient inertia in the NEM will likely arise from a separation contingency event which results in the islanding of an area of the transmission network. A level of inertia will be required to be online at the time that the contingency occurs to both limit the size of the RoCoF caused by the separation event and also to maintain a secure operation of the islanded system immediately following the separation event.

Since October 2016 AEMO has applied a RoCoF constraint on the Heywood Interconnector between Victoria and South Australia. The effect of the constraint is to limit power flows on the interconnector so as to cap the size of the RoCoF that would occur should the interconnector suddenly fail. As identified in the final determination for the *Inertia ancillary service market* rule change request, there has likely been some market benefit opportunities in South Australia for the alleviation of the inter-regional RoCoF constraint.[293]

However, since May 2017 AEMO has been applying additional constraints in South Australia to maintain minimum levels of system strength. The purpose of the constraints is for a minimum level of synchronous generation to remain online at all times to address issues of low system strength. The minimum level of synchronous generation required to be online increases with the output of non-synchronous generation.[294] A description of AEMO's system strength constraints is provided in Box 8.1.

While the requirement for a minimum number of synchronous generators relates to maintaining minimum levels of system strength, the additional inertia provided by these generating units has meant that the Heywood interconnector has not bound since the system strength constraint was put in place. This suggests that there may be limited economic benefit to be gained from the introduction of a market mechanism to provide additional inertia at this time.

AEMO notes that the constraints associated with the system strength requirement have bound for 355 hours between their introduction in early July 2017 and the end of September 2017.[295] Therefore, market benefits may be achieved in the short term by delivering additional synchronous capability to alleviate the system strength constraint rather than the inter-regional RoCoF constraint. However, the alleviation of the system strength constraint requires synchronous capability in specific locations and for specific combinations of generating plant. The Commission agrees with AEMO that it would be difficult to derive a marginal price bringing this additional capability online to alleviate

293 See: https://www.aemc.gov.au/rule-changes/inertia-ancillary-service-market

294 AEMO, South Australia System Strength Assessment, September 2017, p. 5.

295 AEMO, Inertia ancillary service market rule change request - Submission on the consultation paper, p. 4.

the system strength constraint and allow for greater generation from non-synchronous wind.

Minimum required level frameworks to commence 1 July 2018

The final rule made by the Commission relating to the *Managing the rate of change of power system frequency* rule change places an obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island and, for each sub-network, to:

- determine the minimum required levels of inertia
- assess whether a shortfall in inertia exists or is likely to exist in the future.

The implementation of the final rule requires that AEMO must publish the inertia requirements methodology by 30 June 2018, setting out the process it will use to determine the inertia requirements for each inertia sub-network. AEMO must also make a determination of the inertia requirements for each inertia sub-network by 30 June 2018 applying the initial inertia requirements methodology.

A similar requirement has been applied to AEMO under the final rule on the South Australian Government's *Managing power system fault levels* rule change request in relation to minimum levels of system strength.[296]

It is not clear at this stage what the minimum required levels of inertia and system strength will be. However, this will have an impact on the extent to which there is residual market benefit to be obtained from the provision of additional inertia above this level.

The minimum required levels of inertia are likely to be relatively low as they are intended only to be sufficient to maintain the islanded system in a secure operating state under specific highly constrained conditions.

However, power system equipment that provides inertia, such as synchronous generating units and synchronous condensers, also provides system strength. Depending on the size of the minimum required levels of system strength, it is possible that some additional inertia may be provided by virtue of meeting the minimum system strength requirement. This additional inertia may provide for some consequential market benefit by allowing for a more unconstrained operation of the power system.

Likely future needs for inertia and fast frequency response

To date, the focus for an additional inertia requirement has been on South Australia. It is not apparent at this stage, the extent to which other regions of the NEM may require the provision of additional inertia and therefore it is not clear that the alleviation of the

296 See: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

inter-regional RoCoF constraints would provide an accurate value of inertia in regions other than South Australia.

However, as the generation mix changes through the increased penetration of non-synchronous generation and the subsequent retirement of large synchronous generating units, the requirements for inertia will also change. Inertia is likely to become more valuable into the future and therefore the development of a market mechanism for additional inertia for market benefit is likely to be required to provide accurate price signals to promote efficient investment and to provide economic benefits to consumers. AEMO undertook analysis of the emerging risk of high RoCoF occurring across the NEM following credible and non-credible contingency events. AEMO indicated that the objective of the analysis was:[297]

> "… to provide an indication of the challenges in maintaining the frequency operating standard due to high RoCoF, illuminating some of the potential opportunities for different FFR services."

AEMO's analysis indicates that historically (over the period 2011/12 to 2015/16), the maximum RoCoF was 0.2 to 0.3 Hz/s which occurred for up to 17 per cent of the time. AEMO noted that at this level of RoCoF there is less than two seconds for primary frequency control actions to arrest the frequency decline before frequency leaves the containment band and that this is quicker than the commonly observed response from many synchronous governors, suggesting that the frequency operating standard may not be met in these cases.

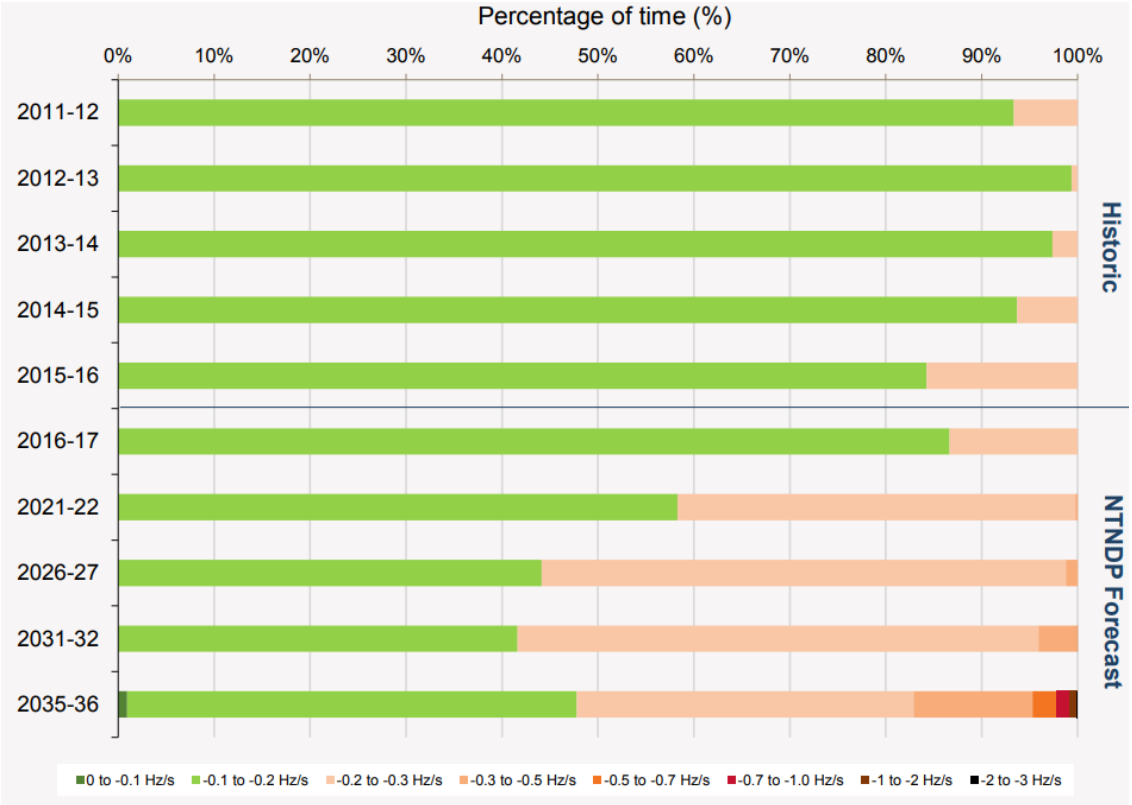
Critically, the percentage of time that this RoCoF would apply after a credible or non-credible contingency was forecast to increase to more than 40 per cent by 2021/22 and over 55 per cent by 2026/27. Further, by this time, a RoCoF of 0.3 to 0.5 Hz/s could be expected some small proportion of the time. AEMO's analysis is set out graphically in Figure 8.1.

AEMO's analysis suggests that more extreme RoCoF levels exceeding 0.5 Hz/s are not expected to be significant for credible contingencies until sometime in the 2030s

AEMO's analysis was undertaken prior to the Commission's final rule on the *Managing the rate of change of power system frequency* rule change request, and so it is unclear the extent to which the minimum inertia obligation on transmission network service providers would affect the outcomes of the analysis.

297 AEMO, *Fast frequency response in the NEM - working paper*, Future power system security program, August 2017, p. 14. See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf

Figure 8.1 Mainland NEM: Negative RoCoF exposure for credible contingency events[298]



Box 8.1 AEMO's system strength constraints

AEMO has conducted power system studies to evaluate the adequacy of system strength for a range of operating conditions, including various levels of synchronous and non-synchronous generation, with normal operating conditions in South Australia.

This analysis has identified that a more complex arrangement of synchronous machines must remain online, to maintain sufficient system strength for various non-synchronous generation dispatch levels. In order to address low system strength in South Australia, AEMO has applied and maintained a system strength constraint since 2 July 2017.

The constraint introduces a requirement for minimum numbers of large synchronous generating units to be operating at all times in accordance with the level of non-synchronous wind generation online:

- between zero and 1200 MW of wind generation, there must be three synchronous generating units online
- with more than 1200 MW of wind generation, there must be four

298 AEMO, *Fast frequency response in the NEM, - working paper*, Future power system security program, August 2017, p. 15

synchronous generating units online.

The constraint acts to constrain back the level of wind generation, which allows for a higher proportion of synchronous generation to meet demand. At times, AEMO may also direct synchronous generators to come online.

Details of the technical analysis that supports these South Australian system strength requirements, and the permitted configurations of synchronous generating units, were published by AEMO on 6 September 2017.[299]

8.2.2 Time frames for the integration of new frequency response technologies

The approximate order in which AEMO's analysis suggests FFR may become valuable in the NEM based on anticipated power system needs is:[300]

- Emergency response FFR, including an under-frequency load shedding scheme and fast response battery storage, is being implemented immediately as a part of the special protection scheme under development to protect against or prevent the loss of the Heywood interconnector connecting South Australia to Victoria[301]
- Contingency FFR and primary frequency control show promise in the near term
- Fast response regulation may become important in future, and is technically feasible at present
- Simulated inertia and grid-forming technologies are not yet commercially demonstrated. Some non-synchronous technologies can provide a very fast response which may be equivalent to an 'emulated' synchronous inertial response. To AEMO's knowledge, such alternatives have not yet been proven as a complete replacement for synchronous inertia.[302]

AEMO states that it is looking at facilitated proof of concept projects in order to build confidence in the capability of FFR to deliver the frequency control services required in the NEM.[303] AEMO is pursuing collaborative opportunities with ARENA and market participants to develop trials of new services, including FFR.

As part of its reference paper on power system requirements, AEMO notes that it is seeking to work with project proponents to ensure new technologies have been subject to a rigorous innovation funnel and incorporated into NEM systems. AEMO suggests

299 AEMO, South Australia System Strength Assessment, September 2017, p. 1.

300 AEMO, Fast frequency response in the NEM - working paper, August 2017, p. 5.

301 Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. The operational goal of emergency frequency control schemes is to act automatically to arrest any severe frequency deviation prior to breaching the extreme frequency excursion tolerance limit, and hence avoid a cascading failure and widespread blackout.

302 AEMO, *Power system requirements – reference paper*, March 2018, p. 15.

303 Ibid, p. 20.

that this should ideally occur in a timeframe which permits the new technology to support any emerging shortfalls in the service.

There are a number of examples of new technologies and approaches being integrated and trialled in the NEM. These include EnerNOC's aggregated contingency raise resource which has been participating in the six second, sixty second and five minute FCAS raise markets since October 2017, the Hornsdale Power Reserve which has participated in all eight markets, and wind farm trials at the Hornsdale Stage 2 wind farm in South Australia and the Musselroe wind farm in Tasmania assessing the feasibility of wind farms participating in all FCAS markets.

- EnerNOC have indicated that their FCAS resource is comprised of distributed, aggregated switching controllers installed at commercial and industrial energy users' facilities throughout the NEM. The MW quantities that EnerNOC bids into the market vary by trading interval, in line with customers' production schedules and real-time demand. Participating customers come from the cold storage, industrial, and forest products manufacturing sectors, and also includes behind the meter batteries. Of the controllers capable of responding fast enough for the R6 market, the vast majority provide a 'Fast Frequency Response' in less than 250ms.[304]

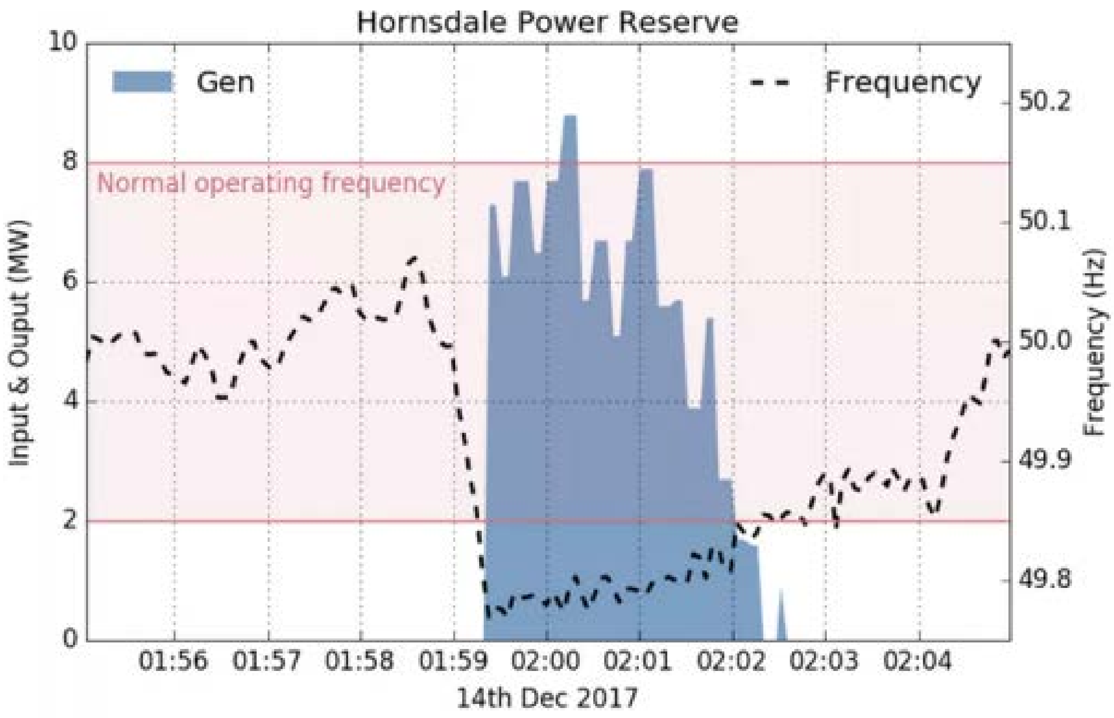
- Since it began offering FCAS in December 2017, the Tesla Hornsdale Power Reserve has been consistently enabled in all eight FCAS markets. At times, the Hornsdale Power Reserve has provided regulating FCAS quantities in excess of the local South Australian requirement. (The local requirement is for 35MW of regulating raise and regulating lower to be enabled within SA). Figure 8.2 shows the response provided by the Hornsdale Power Reserve following the trip of one generating unit at Loy Yang A on 14 December 2017.

- The Hornsdale wind farm trial was announced in August 2017 and was a joint ARENA/Neoen project aimed at establishing the feasibility of wind farms providing both regulation and contingency raise and lower services. The technical basis of the trial was to test the ability of wind farms to participate in the regulation FCAS market through pre-curtailment of output. It involved testing the technical capability of Type 4 wind turbines to be remotely controlled by AEMO followed by a 48 hour market trial to test the ability of the wind farm to fully participate in NEM energy and FCAS markets. This trial has now been completed and results are expected to be released soon.

- The Musselroe wind farm trial was announced in March 2018 and is a joint ARENA/Woolnorth project aimed at extending the work undertaken at Hornsdale. The trial intends to investigate the technical feasibility of providing FCAS and the economic and commercial viability of the wind farm to provide ancillary services and participate in FCAS markets.

304 EnerNOC, Submission on the *Reliability frameworks review* interim report, February 2018, p. 15.

Figure 8.2 Frequency response from the Hornsdale Power Reserve[305]



A number of stakeholders have noted that technologies exist presently that are capable of being actively used to deliver response times of less than one second to the power system. Tesla notes the Tesla Powerpack has a response time of less than 200 milliseconds, which falls within the range of FFR technical specifications which are being explored.[306]

Tesla also noted in its submission that it does not agree with AEMO's assertion that simulated inertia and grid-forming technologies are not yet commercially demonstrated. Tesla and S&C Electric both noted that there are a large number of demonstrated micro-grid projects in the market with inverters operating in grid forming mode that maintain a simulated grid voltage and frequency, which would provide useful information for AEMO.[307]

A number of stakeholders recognised the opportunities available from FFR technologies but suggested that the current concerns around the deterioration of frequency performance under normal operating conditions should be addressed first. S&C Electric suggested that FFR should only be developed as a new service once all issues with inertial and primary response from currently connected synchronous generators has been resolved.[308] If current synchronous generators return to providing primary frequency response and sustained inertia, this will modify the amount of FFR required.

---

305 Tesla, Submission on the *Reliability frameworks review* interim report, 6 February 2018, p. 4.

306 Tesla, submission on issues paper, 5 December 2017, p. 5.

307 S&C Electric, Submission on issues paper, 1 December 2017, p. 9.

308 S&C Electric, submission on issues paper, p. 9.

Pacific Hydro suggested that correcting the large synchronous units' responses is critical. Following that, the new technologies can be correctly integrated to provide fast response in a manner that is co-ordinated, studied and integrated to the overall power system control philosophy.[309]

8.3 Potential broader changes to the design of FCAS frameworks

The above discussion indicates that AEMO faces an increasingly challenging environment in managing higher RoCoF levels, and as such that there may be increasing value from changes to FCAS markets over time. While the timeframe over which new services are likely to be required is uncertain, it does appear to be sufficiently long to allow the changes to frequency control in the normal operating frequency band, discussed in Chapters 5 and 6, to be implemented and consequential impacts assessed prior to any such changes.

As set out in the description of the assessment framework in Chapter 4, the key question for this review is how to create frequency control frameworks that minimise the costs of achieving the frequency operating standard, given the emerging changes in the NEM and associated uncertainties.

8.3.1 Trade-offs inherent in current frequency control frameworks

When evaluating potential substantive changes in FCAS frameworks, it is necessary to consider that the achievement of higher levels of system security, through enhanced frequency control, is likely to entail a cost trade-off. It is possible that enhanced frequency control, delivered through a greater volume of ancillary services or stricter requirements on market participants, will involve an additional cost, which may increase the price of electricity to consumers. It is equally possible that optimising the design and implementation of FCAS markets may enable the delivery of enhanced frequency control at no additional cost or even with a cost reduction.

Broadly, delivery options can be thought of as reflecting greater or lesser reliance on two principal approaches, namely:

- market-based mechanisms
- intervention or regulatory mechanisms.

There are different costs and benefits for market-based or intervention-based approaches. Intervention or regulatory based approaches tend to involve a centralised or direct control over security, which provides a high degree of certainty that a secure supply of electricity will be achieved. However, such an approach will likely foreclose the considerable potential benefits of a well-functioning market, imposing costs and risks on consumers. In these cases, a more distributed control over the provision of services can achieve economically superior outcomes, but may reduce levels of

309 Pacific Hydro, submission on issues paper, p. 12.

confidence where security concerns are manifesting in operational time scales or where the risk external to the energy market prevents it from being well-functioning.

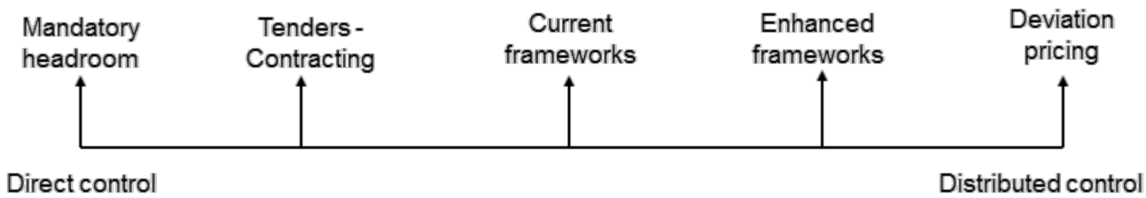
The existing frequency control framework, as set out in Chapter 2, is largely market-based, but does have some elements of intervention intrinsic in its design, such as generator technical performance standards and associated governor or inverter settings.

8.3.2 The spectrum of potential FCAS frameworks

In developing examples of possible alternatives to or enhancements of the FCAS framework that might be adopted in providing frequency control services, the AEMC used a spectrum from extremes of direct (centralised) control of the provision of frequency control services through to fully distributed (decentralised) control as illustrated in Figure 8.3.

Direct control assumes a central determination of the level of frequency response that is then provided by market participants, while decentralised control assumes that market participants determine the level of frequency response to be provided in response to incentives.

Figure 8.3 Spectrum of frequency control frameworks



The spectrum is anchored on the left at the direct (centralised) control end by a framework based on a mandatory obligation for all generators/market participants to both have the capability to be frequency responsive and to provide a defined level of headroom consistent with ensuring a suitable frequency standard is maintained. This headroom could be utilised through a mixture of central dispatch instructions (AGC) or local measurement and local response to frequency disturbance (primary frequency regulation). By specifying the requirements of each market participant, a mandatory headroom approach provides the most direct control of the level of frequency response.

The opposite end of the spectrum (fully distributed or decentralised control), is characterised by some version of a deviation pricing model where frequency control is undertaken by market participants through local response to locally measured frequency deviations. Decisions to be frequency responsive are made by each market participant in response to incentives provided through a transparent pricing mechanism. By pre-determining the price to be paid, market participants are free to make decisions around the level of frequency response that they wish to provide.

In between these approaches at either end of the spectrum, are a number of additional example frameworks. The current market based FCAS framework represents a central point, and is bounded on the left side by a contract/tendering option, and on the right side by an enhanced framework with individual market participant forecasting.

A contract tendering framework would represent a more centralised approach where the volume of required frequency response would be determined substantially ahead of time to allow the contracting process to be undertaken. Conversely, a framework based on individual market participant forecasting would represent a more decentralised approach by allowing market participants to take responsibility for their contributions to the need for frequency control services through FCAS cost recovery arrangements based on the accuracy of forecasts.

Further detail on the design of each of these illustrative frameworks is set out in section 8.4.

8.3.3 Fundamental changes to the NEM energy-only arrangements

The spectrum of frameworks set out above would all operate in parallel with, or be integrated as part of, the existing NEM design. The frameworks represent a range of potential changes that could be made to the existing FCAS frameworks without the need to contemplate substantial changes to the design of the wholesale energy market.

Any review of FCAS frameworks needs to be considered in the context of broader changes to the design of the market, such as the introduction of a day ahead market. The suitability of a day ahead market for the NEM is being considered by the Commission in its *Reliability frameworks review* and is outside the scope of this review.

8.4 Descriptions of example frequency control frameworks on the spectrum

This section provides a description of each of the example frameworks set out on the spectrum.

8.4.1 Mandatory headroom

The mandatory headroom framework is an obligation for all generators and relevant market participants to have the capability to be frequency responsive and to provide a defined level of headroom consistent with ensuring a suitable frequency standard is maintained.[310]

In effect this obligation would require that in order to participate in the wholesale energy market, potential participants would need to have the technical capability to be

310 The definition of generators and market participants subject to the mandatory obligation would need to be developed. For example, it might be limited to scheduled generators or all generators above a threshold installed capacity. The extent that the obligation applied to demand side participants would need to be assessed in terms of capability and potential costs.

frequency responsive (i.e. to vary output or consumption in response to locally measured frequency deviations and/or to a centrally signalled response, and to maintain a centrally mandated level of headroom. That is, to maintain a level of spare capacity to be able to immediately respond to either a frequency raise or lower requirement (or potentially a combination of both).

A key consideration of imposing an obligation on market participants to provide the required frequency control services is the level at which the obligation would be set. AEMO would likely be best placed to determine the level of the obligation in light of analysis of system needs and over a time frame consistent with changes in underlying system requirements. Setting the optimum level of headroom required would likely be a challenging task and there may be limited incentives on AEMO to minimise costs which may result in a standard that over or under delivers on frequency performance.

Any costs associated with providing both the technical capability and associated headroom would be borne by the market participant. These costs are likely to vary by market participant, with incumbent generators facing potentially higher costs should the retrofit of generating facilities be required in order to meet the obligation. This may have an effect on the economic life of some existing generating plant.

Further, imposing new requirements on existing generators might be challenging legally as it has the potential to impact on the accrued rights of generators under existing connection agreements. However, an obligation imposed only on new entrants may require the obligation on each generator to be set at a high level to provide the required amount of frequency response needed to maintain a secure system. This has the potential to impose significant costs on new entrants, which could result in significant barriers to entry, potentially limiting the number or type of participants seeking to enter the NEM.

Considerations

There are a number of considerations which may influence the practicality of such a framework, including:

- The obligation could be extended to include other characteristics such as speed of response or provision of inertia thereby increasing the certainty over the characteristics of the service being delivered and its capability to achieve the desired frequency control outcome
- Under a mandatory obligation, generators might not necessarily have to physically provide frequency control services themselves but might be permitted to meet their obligations by contracting with other providers. However, it would be important under such a scheme for AEMO to have visibility of how generators' obligations were being met. That is to say that it would not be sufficient just to financially penalise non-compliance – the under-provision of inertia may need to be made good in order to maintain the secure operating state of the power system.

8.4.2 Tenders/contracting

The tenders/contracting framework (referred to as the contracting framework) is based on the procurement of frequency control services through a centrally managed process involving some mixture of tenders and/or individually negotiated contracts.

The development of a contracting framework would require the establishment of a set of guidelines and procedures outlining the process for conducting an expression of interest or invitation to tender and the process for entering into contractual arrangements. Specifications of the service could also be outlined including a description of the proposed services, details of the facilities that may offer to deliver the service, levels of performance required, proposed charges, modelling data, testing evidence etc. It could also set out at a high level process for negotiating bilateral arrangements, and any minimum terms and conditions that should be included in contracts.

The form and characteristics of the contracts would also need to be carefully considered. The details of the provision of the service would need to be outlined in the contract, i.e. what are the availability obligations for the provider over the term, how will the service be dispatched and what other operational protocols need to be considered. Payments could be structured either as a fixed charge or a usage payment or both.

Similarly, detailed system models and tools would be needed in order to analyse tender submissions, including the location of services, potential impact on system constraints, and contracting with generators with low RoCoF withstand capability.

A key difference between a contracting framework and the current market based approach is the timeframe over which the procurement of services occurs. Under the current arrangements, services are procured through a market auction process for every five-minute dispatch interval, whereas under the contracting framework, the timeframe could range from weeks or months, to a potentially extended period over a number of years.

Considerations

There are a number of considerations which may influence the practicality of such a framework, including:

- Either AEMO or relevant TNSPs could be charged with procuring services with AEMO likely to be well placed to determine the volume of services required and the conditions of contracts to optimise the availability and provision of the services. However, AEMO would be required to work closely with network service providers and potential service providers to develop detailed system models and tools to analyse tender submissions.

- A contracting approach does not of itself suggest any particular approach to recovery of associated costs. However, a contracting framework would likely limit the ability to place incentives on market participants to minimise the need to procure services. The long-term nature of contracts would likely prevent the establishment of a connection between participant behaviour and volume and the costs of required frequency control services. As such, a simple smearing of costs across all market participants may be the best option in terms of minimising administrative costs and recognising the limited potential for positive incentives driving desirable behaviour.

8.4.3 Enhanced framework with market participant forecasting

The enhanced framework with market participant forecasting approach is based on using forecast accuracy as a proxy for good frequency control. That is, the approach assumes that where all parties have responsibility for their own forecasts, and are held accountable for the accuracy of those forecasts, that they will have sufficient incentive to develop accurate forecasts or to maintain a generation or consumption trajectory that is consistent with their forecast.

Under current regulating FCAS cost recovery arrangements, the causer pays framework aims to provide an incentive for market participants to support good frequency control by allocating costs to market participants whose output variation compared to an ideal dispatch profile is assessed to have contributed to frequency variations.

Similar to current arrangements, the enhanced framework is based on the principle that market participants should be financially liable for their own contributions to the need for frequency control services. However, this new framework would allow market participants to determine their own dispatch profile by providing forecasts to AEMO of their own expected generation or consumption. The difference between each market participant's actual generation or consumption and its forecast would determine its liability for making payments to recover the costs of the required FCAS.

A key element of this framework is that AEMO would no longer pre-determine a volume requirement for FCAS and pay an enablement fee for regulating FCAS. Instead, AEMO would respond to observed frequency variations and dispatch (via AGC) market participants who have provided bids in the relevant regulation FCAS market (raise or lower service). In effect, this would be a dynamic real time process for the procurement of regulating FCAS in accordance with the prevailing market conditions.

Importantly, the new framework would give each market participant an enhanced means of minimising its impact on the need for frequency control services. Each market participant would be liable for paying a share of the costs of FCAS based on the extent to which its forecast was inaccurate. This would create an incentive for market participants to provide more accurate forecasts or to take actions to deliberately meet their forecasts, thereby minimising the requirements for FCAS, and providing a means for market participants to manage their liability under FCAS cost recovery arrangements.

The enhanced framework has three principal components:

1. Market participants provide forecasts to AEMO for their expected generation or consumption over the next dispatch interval.

2. AEMO sets energy market dispatch targets for each dispatch interval based on forecasts and dispatches FCAS within the dispatch interval in accordance with market offers and the measured level of frequency variation.

3. Market participants are liable for FCAS costs in proportion to their actual deviation from forecast.

Market participants submit forecasts to AEMO

In each dispatch interval, each market participant would voluntarily submit a forecast of its expected generation or consumption over the next dispatch interval. AEMO would use the forecasts to set dispatch targets for each market participant, which would follow the market participant's forecast trajectory. For any market participant that chooses not to submit a forecast, AEMO would set a dispatch target based on a linear trajectory as usual. If an individual market participant's actual generation or consumption is different to its forecast trajectory then it would be liable to pay for the FCAS needed to correct the frequency.

Forecasts would need to be based on a continuous trace of four-second time intervals over the five-minute period, although a market participant could assume a linear trajectory for simplification purposes and manage any resulting residual forecast accuracy risk through other means. This would allow AEMO to determine an individual market participant's contribution to the need for FCAS during the dispatch interval.

Forecasts may be a linear trace or something more profiled, depending on the preferences of the forecasting participant. For example, a large industrial load may choose to submit a relatively flat profile, while a grid-scale solar farm may choose to submit a more specific profiled forecast based on expectations of local cloud movements over the next five minutes. Each market participant's actual generation or consumption would be metered over the five-minute period. The aggregate difference between all market participants' actual generation or consumption and their forecasts over the five-minute period would determine the requirement for AEMO to dispatch FCAS from providers to manage system frequency.

AEMO determines FCAS payments and cost recovery

As with the current framework, market participants would submit offers to AEMO for the provision of FCAS. AEMO would dispatch FCAS providers to correct frequency when needed in accordance with their market offers.

Importantly, there would be no mechanism to recover costs from market participants at times that FCAS is not needed, so payments to FCAS providers would only be for usage and not enablement. This is a distinct difference from the current framework where providers of FCAS are paid for maintaining headroom and providers are not explicitly paid for activation of services.[311]

Market participants would have an incentive to submit accurate forecasts in order to reduce their potential exposure to FCAS costs. For non-scheduled generators such as intermittent wind and solar, this would drive an incentive to improve short-term forecasting capability of generation output. For a scheduled generator or load, the potential exposure to FCAS costs would provide an incentive to maintain a trajectory consistent with its forecast.

Market participants would also have the option of entering into a contractual relationship with other participants to counteract their deviations from forecast in real time. For example, a non-scheduled generator may enter into a physical contract with a grid-scale battery operator to respond when the non-scheduled generator's output deviates from its forecast. The non-scheduled generator would send a direct signal to the battery operator to increase or decrease output in an equal and opposite direction from the generator to compensate for the deviation. This would counteract any impact on the supply demand balance from the non-scheduled generator and thereby minimise any consequential impact on system frequency. In such instances, AEMO would need to be informed in order to take the contractual relationship into account when undertaking the FCAS cost recovery settlement process.

Considerations

There are a number of considerations which may influence the practicality of such a framework, including:

- Under the NER, AEMO has a responsibility to maintain system security and may need to be given some discretion to discard or adjust market participants' forecasts if it believes them to be unrealistic. However, there would be a strong financial incentive on the market participant to provide a forecast that it could actually meet.
- Not all market participants would immediately be able to participate in providing forecasts. For example, retailers may have difficulty in forecasting expected consumption and may not be able to accurately meter consumption without the installation of four-second metering devices at the household level.
- Payments may be made regardless of whether the actual deviation helped to correct frequency or not. This would provide an incentive for market participants to provide accurate forecasts or be as close to their target trajectory as possible. However, this may have unintended consequences if generators were penalised for assisting frequency and therefore chose to be less responsive to frequency changes as a result.

311 For FCAS raise services, providers are also paid the energy spot price for the additional power generated.

8.4.4 Deviation pricing

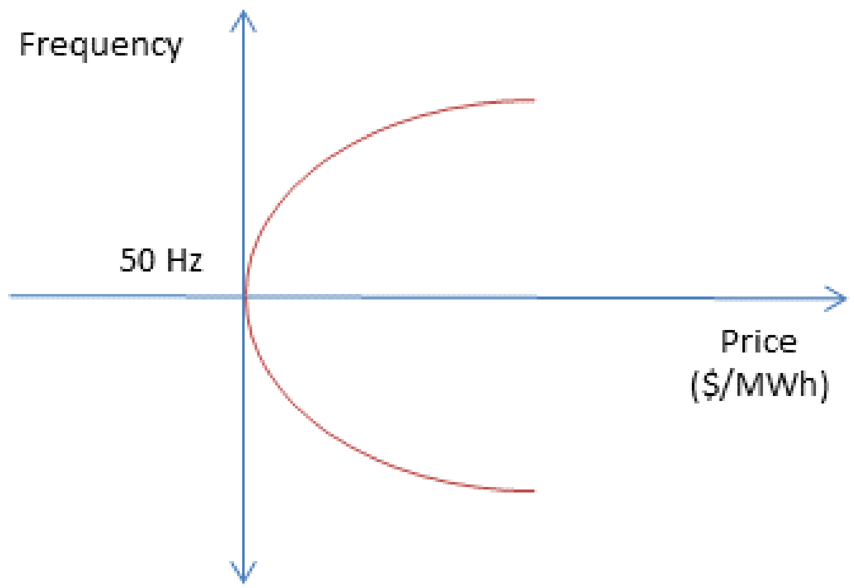
The deviation pricing framework represents a decentralised model in which frequency control is undertaken by market participants through local response to locally measured frequency deviations. Decisions to be frequency responsive are made by each market participant in response to incentives provided through a transparent pricing mechanism.

Market participants are paid if their actions assist in moving the system frequency back towards 50 Hz. The cost of these payments is recovered from market participants that contribute to the frequency deviations. This would provide an incentive for market participants to limit the extent to which they deviate from the linear trajectory of their dispatch targets.

The pricing mechanism is based on a transparent symmetric price function with a rapidly increasing incentive (price) as frequency deviates further from the central target of 50 Hz. The maximum level of the price could be set as a fixed value or could be related to the prevailing price in the energy market. The deviation price function is specified and published in advance. This allows market participants to determine their potential liability under the deviation price function in real time by applying the price function to the deviation from their target trajectory.

A graphical representation of the deviation price function is shown in Figure 8.4. The convexity of the price function is necessary in order to drive increasingly stronger incentives as the system frequency moves further away from 50 Hz. The absolute value of the frequency variation at which the price is maximised could be set at the bounds of the normal operating frequency band, or alternatively could extend out into the normal operating excursion bands and generation or load event bands in order to price contingency FCAS through the same framework.

Figure 8.4 Graphical representation of a deviation pricing function



The deviation pricing model would allow all frequency control technologies to be appropriately valued in accordance with the speed and profile of their response. As with current causer pays arrangements, the deviation pricing model would require relatively granular measurement of performance through four-second SCADA data. However, this data would only be required for settlement purposes.

The deviation pricing model would not require data metering in real time to determine the level of frequency response required. The only requirement is to be able to measure system frequency in real time in order for each market participant to evaluate the likely costs of its actions in relation to system frequency. As such, data management and quality issues associated with four second performance data are unlikely to present an obstacle to the operation of the deviation pricing model.

If deviation pricing were to be extended to contingency FCAS then the speed of response would be greater, in which case high speed metering would be needed so that the providers of helpful deviations can be paid and the providers of harmful deviations, of which the cause of the contingency would be the largest, can be charged.

Considerations

There are a number of considerations which may influence the practicality of such a framework, including:

- In the initial stages, there would likely be some uncertainty over the level of response that would be provided and the quality of frequency control that could be achieved. It is possible that the deviation pricing model could be run in parallel with the current FCAS framework in order to transition to the new arrangements. This may require fair value payments to be calculated and charged to participants with helpful deviations in order to avoid potential double dipping.
- The price function for the calculation of deviation settlements would need to be determined and updated periodically. The price function could potentially be calibrated on the basis of historical FCAS price outcomes, through an estimation of the marginal value of frequency performance, or through a means of progressively increasing the deviation price function over time until the desired level of frequency performance is achieved.
- The deviation price function also has the potential to value the provision of inertia through the addition of a RoCoF component. This separate component of the deviation price function would provide a payment to providers of inertia based on the value that inertia provides in slowing down a frequency descent through positive deviations and slowing down a frequency ascent through negative deviations.

Crediting positive contribution factors under the causer pays procedure

As set out in Chapter 5, the Commission recommends that the providers of a primary regulating response should be remunerated for the costs of providing the service, in particular where the costs of maintaining headroom to provide the service are likely to be high. The Commission considers that changes to the causer pays arrangements to facilitate the provision of incentive payments for primary frequency regulation may be one approach to support improved frequency control during normal operation.

The deviation pricing model is comparable to this extension and revision of the current regulation FCAS causer pays procedure, in that participants that contribute to good frequency control are rewarded (through payments for positive contribution factors) and costs are recovered from participants that cause frequency deviations (with negative causer pays factors).

However, in this adjustment to the causer pays arrangements, AEMO would still be pre-purchasing headroom (MWs) through making enablement payments. Unlike the deviation pricing model, such an approach still has a significant role for a central procurement authority and as such does not represent the fully decentralised end of the control spectrum discussed above. An additional complexity is that the cost associated with any pre-purchase of headroom will need to be recovered in addition to any costs associated with incentive payments for positive contribution factors, potentially increasing the total cost of frequency control under normal operating conditions.

Under a fully decentralised approach, deviation pricing would not involve any pre-purchase of headroom (or participation in the regulation FCAS market) but would simply rely on market participants responding to pricing incentives to act in a way that supports good frequency outcomes. It is assumed that where incentives are sufficient, that the self-interest driven behaviour of market participants would ensure that the desired frequency quality is achieved. A similar approach to the deviation pricing model has been proposed by Intelligent Energy Systems (IES) and is described in Box 8.2.

Box 8.2 Intelligent Energy System's (IES) proposed model for improvements to system frequency

CS Energy, in its submission to the *System security market frameworks review*, provided a report prepared by Intelligent Energy Systems (IES) which details a package of reforms to incentivise market participants to maintain system frequency for secure operation of the power system.[312] There are a number of design similarities that can be drawn from these proposed reforms and the deviation pricing mechanism.

The IES report focuses on three key areas for reform and proposes a number of

[312] CS Energy, System security market frameworks review – submission on directions paper, 5 May 2017.

changes to the design of current pricing and settlement arrangements:

1. **Arrangements that operate within the half hour trading interval**

   — *A four-second settlement period* – The proposed design includes the use of a four-second settlement period using specially programmed fast meters to record the output/consumption of market participants and base settlement on these meter readings.

   — *The use of a ramping energy price* – The report considers a ramping energy price would mitigate step changes in energy output and encourage participants to respond to prices over a range of intervals rather than focus on dispatch boundaries. The energy price, rather than being flat in each trading interval as in the current arrangements, would ramp linearly between consecutive dispatch prices.

2. **The national electricity market dispatch engine (NEMDE)**

   (a) *An enhanced AGC system* – The existing AGC system calculates frequency deviation targets for each enabled regulation FCAS provider in each interval, which is then communicated to providers. In the proposed design reforms, NEMDE would be enhanced to take account of the costs to providers of following these targets: e.g. the cost of wear-and-tear from cycling up and down.

   (b) *Shadow price for energy* – An enhanced AGC system would allow a shadow price for energy to be established which would then be used to set the price for frequency deviations.

3. **Fees and charges**

   (a) *Settlement for frequency deviations* – In the proposed design, the settlement for frequency deviations would be calculated in each four-second interval and be based on deviations from base system frequency. Deviation quantities would be calculated based on the difference between the metered quantity and a derived baseline quantity. The price associated with deviations would then be applied to the deviation quantities to determine deviation settlement amounts.

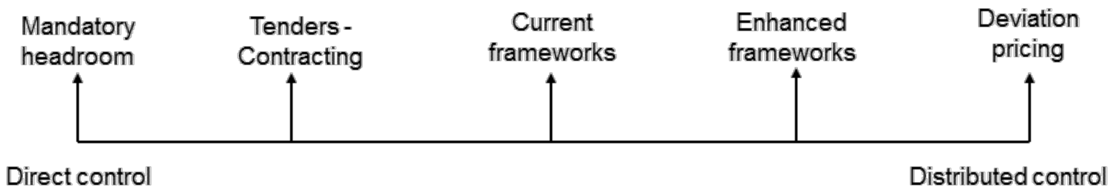
   (b) *Fast deviation and inertial response* – The proposed design allows for settlement to be adjusted to recognise the value of fast deviation and inertial responses. During a post-contingency frequency excursion, the deviation interval would be reduced to a sub-second length to allow for fast responses to be measured.

   (c) *A decentralised approach for settlement calculations* – The proposed design includes the use of specially-programmed fast meters to calculate deviation price and settlement amounts in real-time, with the accumulated amounts (e.g. over a day) then transferred to AEMO. The report suggests this would avoid the need to store and transfer all of the fast metering data, which would be required under a conventional centralised-settlement arrangement.

The proposed approach includes a two-stage phased implementation of reforms. In stage 1, only enabled FCAS providers would participate and be paid the deviation price based on their response while non-enabled parties would not be paid. This approach would replace the existing FCAS arrangements. In stage 2, all parties would participate and be paid based on their response.

8.5 Addressing the drivers of change through changes to FCAS frameworks

As set out in section 8.3.2, the possible alternatives to current FCAS frameworks discussed in this chapter sit on a spectrum of direct centralised control to decentralised distributed control of the provision of frequency response. This spectrum represents a trade-off between higher levels of certainty and confidence in the maintenance of system security on the left side and increased efficiency and flexibility in the provision of services on the right side.



The relevance of adjusting the existing FCAS frameworks towards either direction on the spectrum can be informed by the extent to which the drivers of change outlined in Chapter 3 are addressed by any such change. This section discusses the ability of the different FCAS frameworks identified on the spectrum to address the future requirements of the power system, including:

- reducing barriers to the participation of emerging technologies in the provision of frequency control services
- co-optimising the provision of frequency control services with inertia
- coordinating the locational requirements of frequency control services and other system security constraints, such as system strength
- reducing the potential variability and unpredictability of supply demand imbalances.

8.5.1 Reducing barriers to emerging technologies

The existing frequency control frameworks were largely established when the technical characteristics and capabilities of the generation mix were very different. As the generation mix changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve. There may now be opportunities for the new energy technologies being connected to provide services that help support power system security, including frequency control.

As discussed in Chapter 5, the control of system frequency within the normal operating band has conventionally been undertaken through a combination of automatic generator governor response and the provision of regulating FCAS. With the recent decrease in automatic governor response from generators, increases in the provision of regulating FCAS are not likely to be sufficient to address the reduction in frequency performance, and changes to market frameworks will be needed to drive a primary frequency response.

Emerging technologies that are capable of delivering fast active power may play a role in providing this automatic response. FFR services are not a mature technology, and are at an early stage of development or deployment. Such technologies may face barriers to participation with the limited revenue certainty provided by existing FCAS frameworks in circumstances where FCAS revenue is expected to represent a critical share of potential income.

Further, current definitions of the contingency services in the MASS are consistent with the response characteristics of the currently dominant technologies in the NEM. Some new or emerging technologies may be capable of providing a useful and low cost response but do not necessarily conform to any of the timeframes associated with these service definitions.

Ability of different frameworks to efficiently value service provision

The FCAS frameworks on the right of the spectrum, as set out in section 8.3.1, place a financial incentive on market participants to minimise their impact on the need for frequency control services, thereby minimising the quantity of FCAS required to manage system frequency. A key difference between the enhanced framework and the deviation pricing approach is that under the enhanced framework market participants continue to bid into FCAS markets and are centrally dispatched while under the deviation pricing approach, market participants are responding independently to locally measured frequency deviations in response to a known pricing formula.

The key point is that in either case market participants are responding to a single price (either set in the FCAS market or through a transparent pricing formula) and are providing a simplified response i.e. active power injection or removal to increase or reduce measured frequency. Thus, these approaches are generally technology neutral (noting that the continued reliance on existing FCAS markets under the enhanced frameworks means that the service definition may preclude some technologies, a restriction that does not apply under deviation pricing).

A contracting approach would likely provide flexibility to facilitate the provision of frequency response from a variety of participants, including less conventional technologies. A mechanism that involves contracting is likely to have benefits in being able to tailor the requirements for investor certainty with the flexibility to adapt to changing market conditions.

The limited use of some emerging frequency control technologies in power system operation, particularly as a contingency service, suggest that contracts are likely to be an appropriate mechanism with which to procure these services in the short to medium term, should they be deemed to have some valuable characteristic not reflected in other technologies and which would not otherwise be made available.

Mandating a response from market participants may result in a considerable risk of locking out emerging technologies that may provide a useful and low cost frequency response but which are incapable of meeting any mandated minimum frequency response requirements which have been specified.

Ability of different frameworks to provide investor certainty versus flexibility

The enhanced framework with market participant forecasting and the deviation pricing model both offer significant flexibility to vary the required frequency response over time to adapt to changing market conditions. However, both of these approaches may provide limited investment certainty.

To some extent, this may be ameliorated by the ability for market participants to enter into bilateral contracts. Under the enhanced framework with market participant forecasting, contracting would be in the form of an agreement to physically respond when requested to counteract deviations from forecast in real time. Under the deviation pricing model, market participants may enter into fixed price contracts to counteract the potential cash flow implications of exposure to the deviation price function. Both of these methods of contracting, while peripheral to the core design of the framework, would present opportunities for market participants to underwrite their investments in frequency control services with a greater degree of revenue certainty.

A tender contracting approach would likely provide greater levels of investor certainty and potentially reduce risks around investing in emerging technologies. Contracting may be a suitable mechanism for new entrants to provide the service as it may reduce the risk associated with capital expenditure, while also providing incentives for new entrants to enhance their technologies and capabilities to provide lower cost frequency control into the future. Contracting could act as a starting point for the development of a more competitive market.

Consideration would need to be given to the appropriate length of contract duration based on an assessment of the best approach for providing investor certainty and flexibility. For example, if contracts were designed over the longer term at a potentially high capital cost, there is a risk that these assets would become stranded or significantly devalued when improved technologies were developed. There is also a risk associated with short term contracts, as they may not provide the required level of certainty for investment and result in a lack of incentives for the provision of frequency control services, particularly building physical infrastructure.

Mandating a response from FCAS providers would provide a high degree of transparency and simplicity to meeting the requirements of the system and would provide a high degree of certainty that frequency could be maintained within secure limits. However, such an approach would require the nature of the response to be specified, which would not only be a complex process in itself, but would also limit the flexibility and adaptability of frequency response in the system over time. Once a participant met the requirements, there would be no incentive to innovate or invest in faster or more profiled frequency response capability, other than to attempt to reduce the costs of the frequency response already being provided. It is highly likely that the requirements to maintain a stable system frequency would not be met at lowest cost through such an approach.

Further, imposing new requirements on existing market participants might be challenging legally, as discussed in section 5.3.3 which sets out considerations for a mandatory approach to the provision of a primary regulating response. However, an obligation imposed only on new entrants may require the obligation on each generator to be set at a high level to provide the level of frequency control capability that is required to maintain a secure system. This has the potential to impose significant costs on new entrants, which could result in significant barriers to entry and a delay to the provision of the required services.

8.5.2 Co-optimisation of FCAS with energy and inertia

Currently, FCAS markets are co-optimised with the energy market. Market participant offers for energy and FCAS are optimised through the NEM dispatch process to determine the lowest price outcome, subject to constraints. Any inertial response is currently excluded from the calculation of a generating unit's total payments for FCAS provided.[313] However, going forward, FCAS may increasingly need to be optimised against the presence of inertia in each dispatch interval.

Inertia is a distinct service from FCAS. Inertia acts to slow the rate of frequency change caused by a contingency. This is different to FCAS, which actively injects power to arrest the frequency change and revert the frequency back towards normal operating levels.

However, the two services are, to some extent substitutes: greater amounts of FCAS, in particular faster acting FFR services, will reduce the amount of inertia required. Consequently, co-optimisation of the services would likely lead to lower overall cost arrangements.

The time delay associated with FFR technologies response to a measured frequency variation implies that there is a level of inertia that must be online at any point in time

313 AEMO, Market Ancillary Service Specification, 30 July 2017, p. 16.

to resist frequency changes at the time of the contingency event as well as over the first few hundred milliseconds. Beyond this initial time period, active power injection by a combination of FFR and existing technologies can be used to stabilise system frequency.

The time delay in the response of even FFR services means that it would be necessary to design a mechanism which would provide for sufficient inertia to be online to limit high RoCoF at the time of, and immediately following, the occurrence of a contingency event. The same mechanism, or a separate mechanism, could then be used to obtain FFR services to stabilise frequency after the initial time period.

As set out in section 8.1.1, mechanisms have been developed for providing minimum levels of inertia. However, these are predominately targeted at addressing the risk associated with network separation or islanding, as this is where the issues currently lie.

As levels of inertia decline into the future, additional inertia may be required to manage contingencies across the NEM as a whole (e.g. loss of the largest generator). Consequently, any long term change to FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS, with this potentially requiring the development of additional inertia services.

The ability to co-optimise frequency control services would be maximised under those frameworks with the highest degree of flexibility. The current frameworks co-optimise FCAS with energy but do not co-optimise the separate services with each other, the exception being the five-minute delayed contingency services and the regulating services. It is foreseeable that the co-optimisation of frequency control services this could be extended to incorporate a faster response service. However, there are likely to be limitations with effectively co-optimising FCAS and energy with inertia.

The physical characteristics of the supply of inertia may present a number of issues which may inhibit the effective integration of inertia into the existing wholesale energy market dispatch process. Generators provide all of their inertia when they are online or no inertia when they are offline, regardless of energy output. Therefore, any increase in the level of inertia would require the start-up of an additional synchronous unit. This is different to energy where an incremental increase in the demand for energy can generally be accommodated by an incremental increase in the output of the generating units that are already online. As such, while co-optimisation in real time between FCAS and energy is relatively straight forward, real time co-optimisation with inertia may be impractical due to the physical characteristics of synchronous plant.

However, while co-optimisation of FCAS and energy with inertia may present difficulties in real time, it is possible that the provision of inertia could be optimised over time so as to trend towards an efficient level. Such a mechanism would involve the development of a price for inertia which signalled the value of inertia to the system in accordance with the prevailing system conditions. Providers of inertia would respond over time by anticipating when inertia is likely to be most valuable to the system based on the pattern of past price signals.

Ability of different frameworks to co-optimise FCAS with energy and inertia

A key strength of the deviation pricing model is that participant frequency responses are not categorised into separate services and thus the separate services are effectively co-optimised through a continuous price function which values frequency response consistent with the speed and profile of response.

While the deviation pricing model does not explicitly co-optimise frequency response with energy, the price function would be designed to create a sufficient incentive equal to or greater than the opportunity costs to market participants of maintaining headroom in the energy market. Indeed, the price function could be derived directly from the energy market offers of participants.

The challenges of estimating the economically efficient level of inertia are amplified through mechanisms that lie further on the left of the spectrum. A mechanism that involves contracting is likely to have benefits in being able to tailor the requirements for investor certainty with the flexibility to adapt to changing market conditions. However, an analysis of the mix of inertia and FCAS needed to efficiently manage system frequency would likely need to be undertaken at the initial stage of contracting, and there may be little scope to dynamically adjust the mix of services in real time, depending on the nature of the contracts entered into. Furthermore, under such an approach, it may be difficult to develop clear criteria by which competing or disparate offers could be assessed, and that consumers would likely bear the risk of any under- or over-procurement.

A mandatory obligation to provide inertia would evidently provide the most certainty by effectively notifying market participants at the time of their connection of their requirements to provide inertia. Mandating an obligation on market participants would provide investor certainty. However, in order to minimise costs, the level of the obligation is likely to have to be determined upfront. As such, there is a considerable risk that a mandatory obligation may be under or over-specified, increasing the costs of maintaining system security over the long term. A mandatory obligation would provide no ability to optimise the provision of inertia against FCAS in real time.

8.5.3 Location and coordination with other system security services

The location of frequency control sources in the system has implications for the management of system security. The location of the services may have an impact on the ability to manage frequency under some circumstances. For example, the loss of transmission lines can have the effect of isolating areas of the network from the rest of the grid. The ability to maintain a secure power system within the isolated area depends on the level of inertia and active power sources available within the area.

Over time, locational signals are likely to become more important as synchronous generators retire and new potential generation and inertia sources are introduced. Without a satisfactory locational signal, areas within NEM regions may increasingly arise which, due to a lack of generation and inertia, are unable to maintain stable operation under certain operating conditions. This could especially be an issue if these areas are at risk of separation from the rest of the NEM and there is a requirement or expectation that these areas are able to maintain operation as an islanded system. A potential example of this could be the separation of Northern Queensland from Southern Queensland.

Equally importantly, other aspects of system security including system fault levels and voltage control are likely to be substantially impacted by the network location of the services. A secure operating system requires generating units and network components to be able to operate continuously following a major fault or disturbance to the power system, and this ability is diminished by declining system strength.

As compared to system frequency, system strength has much more localised impacts. The system strength at a point in the power system depends on how well it is connected to the synchronous generating units in that part of the power system. The system strength will be higher when:

- there are a number of large generating units nearby
- the point is connected to these generating units with more transmission (or distribution) lines and transformers.

Non-synchronous generators do not contribute to system strength as much as synchronous generating units, if at all.[314] Procurement mechanisms for frequency control, which might lead to investments in new synchronous devices, should therefore be able to consider the location of such investments in order to co-optimise this with any investment required to manage system strength.

Ability of the different frameworks to coordinate frequency control services with other system services

The locational requirements of maintaining a sufficient level of system strength will need to be coordinated efficiently as part of any mechanism to procure frequency control services. This may have the effect of placing constraints around the optimisation of inertia with energy and FCAS. For example, in some cases synchronous generators providing inertia may need to be prioritised due to requirements to maintain sufficient levels of system strength, despite there being potentially lower cost technologies capable of providing FFR.

As with inertia, the level of system strength in the power system is dependent on the combination of synchronous generators that are online at the time. As such, the provision of system strength may need to be coordinated in advance of the relevant dispatch interval.

These types of locational-specific requirements are typically addressed through the application of constraints in the operation of the market. An adjustment of FCAS framework towards more distributed control on the right of the spectrum, would likely

314 Some modern inverter-based generation can provide a limited contribution to system strength.

require the development of constraints to manage system strength requirements. This is the case in the current market environment in South Australia where constraints on the generation output from wind farms have been applied to maintain sufficient levels of system strength, as discussed in section 8.2.1.

As with inertia, the provision of system strength requires the operation of synchronous generators, which typically involve longer start-up times. The adoption of a longer lead timeframe would provide more central control of the levels of system strength and thereby increase the certainty that sufficient levels of system strength will be online at the time of dispatch. This would apply to a mandated approach and a contracting approach.

Both of these approaches would allow for greater direct control of the levels of system strength. A mandated obligation on each market participant to physically provide inertia would result in a broad geographical distribution, which would likely address the locational specific issues associated with system strength. If inertia were to be procured through a contracting option then this would also likely enhance the general levels of system strength.

However, as with inertia, these approaches may suffer from an inability to optimise the level of system strength in real time. This may impact the efficiency of market outcomes if the determination on the level of system strength involves an economic assessment of the value of alleviating constraints on the output of wind generators. Furthermore, inertia and system strength are technical characteristics of synchronous technologies and it may be difficult for non-synchronous technologies to comply with a mandatory approach.

8.5.4 Potential to address variable and unpredictable supply demand imbalances

Currently, AEMO procures FCAS to control frequency in response to unexpected changes in supply and demand. AEMO determines the volume of FCAS required in order to maintain frequency within the limits set out in the frequency operating standards. The level of regulating FCAS is determined on the basis of the expected need to manage small variations in system frequency within the normal operating frequency band. Contingency FCAS is procured for larger events, such as the sudden loss of a large generating unit, and the volume of contingency FCAS is based on the size of the largest potential credible contingency.

As set out in Chapter 3, there is likely to be a potential increase in the need for frequency control services to respond to sudden changes in output from non-dispatchable sources of supply due to changing weather conditions. It is unclear at this stage of the extent to which this will impact on the level of FCAS that AEMO will need to procure in order to manage system frequency. Nevertheless, the Commission considers that there are likely to be benefits in exploring the means by which market participants can be encouraged to reduce their potential impacts on the need for frequency control services.

The current causer pays procedure provides incentives for market participants to minimise their impacts on system frequency through the allocation process for recovery of the costs of frequency control services. The procedures are designed to make market participants financially accountable for their contribution to the need for FCAS. Properly designed causer pays arrangements should create efficient incentives for market participants to minimise their impact on changes to system frequency, thereby minimising the overall level of frequency control services required.

However, as set out section 5.1.2, a number of aspects of the existing causer pays procedure have been identified by stakeholders as potentially increasing costs to market participants or resulting in inefficient outcomes.

Further, as set out in section 8.1.4, in relation to contingency FCAS, the current approach does not capture the extent to which a participant contributed to setting the contingency size and therefore the total level of services required to be sourced.

These design aspects of the current causer pays arrangements blunt the incentives for limiting potential impacts on frequency, and as discussed in Chapter 5, may even have led some market participants to become less frequency responsive.

The Commission supports AEMO's investigations of potential improvements to the FCAS causer pays arrangements, as set out in Box 5.3.

However, while the crediting of positive contribution factors to market participants may create an added incentive to provide a frequency response, such arrangements do not give market participants direct control over their individual impacts on system frequency. This is because the calculation of the positive contribution factors may suffer from the same level of opaqueness and inter-temporal disconnect as evidenced under the current arrangements.

Ability of different frameworks to address variable and unpredictable supply demand imbalances

An alternative to changing the causer pays arrangements would be to adjust FCAS frameworks towards the right of the spectrum, where market participants’ actions are more directly related to their liabilities for the cost recovery of FCAS.

The enhanced framework with market participant forecasting provides market participants with a direct real time incentive to minimise their impact on the need for frequency control services. Under this framework, each market participant provides a forecast of its generation or consumption over the next five-minute dispatch interval, and is liable for paying a share of the costs of FCAS based on the extent to which its forecast is inaccurate. This provides market participants with direct control over their liability for FCAS costs, either by improving the accuracy of their forecasts or by taking deliberate actions to track as close to their forecasts as possible. This framework not only provides a means for market participants to manage their liability under FCAS cost recovery arrangements, but also has the effect of minimising the overall requirements for FCAS.

Under this framework, market participants would also have the option of entering into a contractual relationship with other participants to counteract their deviations from forecast in real time. For example, a non-scheduled generator may enter into a physical contract with a grid-scale battery operator to respond when the non-scheduled generator's output deviates from its forecast. The non-scheduled generator would send a direct signal to the battery operator to increase or decrease output in an equal and opposite direction from the generator to compensate for the deviation. This would counteract any impact on the supply demand balance from the non-scheduled generator and thereby minimise any consequential impact on system frequency.

The deviation pricing model would take this a step further by placing a direct cost on market participants that contribute to frequency deviations. This cost would be precisely equal and opposite to the price paid to those market participants that help to correct the frequency deviation. Under this approach, a transparent price function would be developed which would allow market participants to model and to determine ahead of time the amount needed to be paid towards the recovery of FCAS costs, depending on frequency movements. This has the potential to result in immediate and direct attempts to reduce costs by minimising impacts on system frequency.

8.6 The costs of making changes to frequency control frameworks and the flexibility of the current arrangements

This chapter has discussed potential changes to frequency control frameworks which may be needed over time to meet the future needs of the power system. A spectrum of frameworks has been discussed which, to varying degrees, have the potential to enable participation by emerging technologies and to address the drivers of change identified in Chapter 3.

However, changes to FCAS frameworks are likely to involve their own set of costs, both in terms of implementation but also in the means by which frequency control services are procured. While it is possible to preemptively revise market FCAS frameworks in an attempt to better accommodate emerging issues, this has the risk of imposing potentially significant costs on market participants sooner than may be required or even to lock in changes that subsequently prove to be unnecessary or unsuitable.

Furthermore, the Commission considers that any substantive changes to FCAS frameworks should wait until any revisions to frequency control in the normal operating frequency band are implemented and consequential impacts understood.

The Commission supports AEMO's ongoing investigations into the requirements for the power system to maintain system security. AEMO has proposed to continue to work with stakeholders to convey the most up-to-date information and to explore the opportunities and risks of how technical services may need to change over time.[315]

315 AEMO, *Power system requirements – reference paper*, March 2018, p. 22.

These investigations will support an assessment of the necessity and likely time frames for making changes to frequency control frameworks.

While moving immediately to a completely new set of arrangements for the procurement of frequency control services may not be necessary, the Commission considers there may be some flexibility within the current arrangements to potentially address the deficiencies in FCAS frameworks identified. These include:

- changes to the MASS to redefine the existing services to cater for FFR and the response profiles of some emerging technologies
- changes to cost recovery arrangements for contingency FCAS to improve investor certainty and address the lack of incentives to reduce the requirement for frequency control services.

8.6.1 Changes to the MASS

The MASS currently defines six contingency FCAS markets in the NEM designed to manage frequency control after a system disturbance. As set out in sections 8.1.1 and 8.1.2, an increasingly important question is whether these markets remain relevant in terms of meeting the emerging needs of frequency control in the NEM.

Clause 3.11.2 of the NER sets out the arrangements for market ancillary services. This includes a high level requirement for eight market services in 3.11.2(a) (regulating raise and lower and fast, slow and delayed raise and lower services) followed by the requirement for AEMO to make and publish a MASS containing a detailed description of each kind of market ancillary service together with associated performance parameters and requirements. The Commission's issues paper provided additional detail on FCAS market design.[316]

Of interest in the context of the current consideration of future FCAS frameworks is the extent of the flexibility of the MASS. The key constraint on the MASS in the NER is the requirement for eight markets with:

- regulating raise and lower services being provided in accordance with electronic signals from AEMO
- fast and slow market services provided in response to the locally sensed frequency
- delayed services provided in response to a change in the frequency of the power system beyond a threshold or in accordance with electronic signals from AEMO.

As it is the MASS that specifies the technical characteristics of the services, it is also open for the MASS to redefine the service. For example, the fast service could be redesigned to accommodate wind farm based synthetic inertia which could have a maximum sustain time of 10 or 12 seconds. Alternatively, the definition of the

316 AEMC, *Frequency control frameworks review - issues paper*, November 2017, p. 81.

calculation of the amount of the service could be changed from an approach based on the lesser of twice the time average of the response between zero and six seconds and six and sixty seconds to an approach based on an integral calculation of the total active power able to be injected over the relevant period (perhaps sixty seconds).

Introducing a new faster service in addition to the existing eight services would require a change to the NER. An example of such a service is the two second response (with eight second duration) service introduced in Ireland.[317] Such a service is just one example of a possible FFR service definition. It is equally possible that a one second service or even a half second service could be introduced. There is the potential for multiple FFR markets to be introduced to capture different response elements that are valuable to the system.

A number of stakeholders, in response to the issues paper, support the introduction of a new faster service.[318] The South Australian Government suggests that the different technical characteristics of different FFR technologies make it difficult to design a homogenous service specification.[319] However a one or two second response service that need only be sustained until the existing six second service has responded would appear most consistent with current market arrangements.

A number of other stakeholders do not support the introduction of a new service at this time.[320] EnergyAustralia suggests that current structures are sufficient to support faster responding technologies and that, at present, there is not enough potential supply, nor diversity of providers, to provide confidence that such a market would work well.[321] Care should be taken to ensure that suitable market conditions exist before introducing a market procurement approach.

The Commission considers that introducing an additional FFR market would increase the granularity of the FCAS markets and therefore may provide better price signals for the value of fast response services. However, in circumstances where the ideal FFR service characteristics are not clear, are likely to change over time, or where there may not be a sufficient pool of providers to guarantee competitive supply, development of specific FFR FCAS markets may not be the preferred option.

8.6.2 Changes to cost recovery arrangements

Changes to cost recovery arrangements could potentially be made to improve investor certainty and address the lack of incentives to reduce the requirement for frequency control services. These changes would require amendments to the NER but would likely have lower implementation costs and be less complex than making broader changes to the design of FCAS frameworks.

317 DGA Consulting, International Review of Frequency Control Adaptation, 14 October 2016, p. 12.

318 Submissions on issues paper: ENGIE, pp. 3-4; Clean Energy Council, p. 3; Tesla, p. 6.

319 South Australian Department of the Premier and Cabinet, Submission on issues paper, p. 3.

320 See submissions on the issues paper: Snowy Hydro, p. 11; EnergyAustralia, p. 6; AGL, p. 5.

321 EnergyAustralia, Submission on the issues paper, p .6.

Pass through FCAS costs to market customers

As set out in section 8.1.3, the current FCAS market framework does not readily facilitate secondary contracting of the kind used by wholesale electricity market participants to create revenue certainty and underwrite investments for emerging technologies. This may be largely due to the historically low total costs of FCAS relative to the size of the energy market and the fact that FCAS revenue has not been a significant factor in justifying the initial investment of the majority of the incumbent generators. However, an additional potential factor is that FCAS cost recovery arrangements tend to smear the costs across multiple market participants, which can make it difficult for participants to identify a suitable contracting counterparty with an equal and opposite risk profile.

A potential option for making cost recovery arrangements more conducive for secondary contracting would be to pass all the costs of FCAS through to market customers. This would provide a range of potential counterparties with which providers of FCAS could contract. The exact arrangements for allocating costs among market customers would need to be determined. This would be similar to the energy market where market customers pay for the energy they consume.

Adjust cost recovery arrangements for contingency services to reflect relative generator output

As set out in section 8.1.4, the current cost recovery arrangements for contingency services do not provide incentives on market participants to reduce their potential impact on the need for frequency control services.

As the generation mix changes over time, the FCAS cost implications for the connection of a new large generating unit may become more pronounced and potentially result in the procurement of large volumes of contingency FCAS to cater for a small number of potential contingencies.

A potential alternative approach would be to allocate contingency FCAS costs to generators according to the extent to which the marginal output from those generators creates an additional need for contingency FCAS. Under this approach, payments for FCAS would be higher for larger generating units to reflect the greater volume of FCAS needed to be procured to cater for the sudden unexpected failure of these units. This approach is sometimes referred to as 'runway pricing'.

Draft recommendation 8

That, in the medium term:

(a) AEMO conduct a broader review of the MASS to recognise the capability, and more accurately value the response profile, of new technologies that are capable of providing frequency control services

(b) the AEMC and AEMO refine the time frames and develop a work program for making any substantive changes to FCAS frameworks. This process should be informed by:

(i) an assessment of any consequential impacts arising from the implementation of any revisions to frequency control arrangements in the normal operating frequency band

(ii) investigations to be undertaken by AEMO into:

a. the emerging capabilities of fast frequency response technologies including trials of various technology types, with a view to sharing the outcomes of the trials with relevant stakeholders, and to inform the development of future service specifications

b. the evolving technical and operational requirements of the power system and the inter-relationships between different system services, including frequency response, inertia and system strength

In the short term, the Commission will consider what recommendation it will make, if any, on the receipt of submissions from stakeholders in response to this draft report.

A Stakeholder views on project scope

The issues paper published on this review in November 2017 set out the AEMC's preliminary analysis, and sought stakeholder views on, these issues. In their submissions to the issues paper, stakeholders largely supported the proposed scope of the review, but made a number of suggestions on additional issues to consider. The AEMC's response to these scope issues are set out in Table A.1.

Table A.1 Project scope

Issue proposed by stakeholder to be included within scope	AEMC response
AEMO considered that the scope of the review (as set out in the terms of reference) was too limited and too "solution focused." AEMO proposed that the scope instead target the technical needs of the power system through a staged approach that first considers the needs of the power system.[322]	The AEMC has revised its assessment approach to incorporate AEMO's views on the scope and proposed approach to the review. This is set out in Chapter 4. The AEMC's draft recommendations, set out in this report, also reflect a staged approach to the implementation of solutions to address the issues under consideration.
S&C Electric Company submitted that the issues paper focused on generation and did not assess the impact of demand. It questioned whether demand forecasting and the challenges associated with responsive demand were within the scope of the review.[323]	The AEMC's views on this issue are set out in Chapter 6. This issue is also being explored through the AEMC's *Reliability frameworks review*.
Snowy Hydro considered that AEMO's forecasting errors and its role in determining the amount of regulating FCAS in the normal operating frequency band were not properly explored in the issues paper, and should be considered in more detail through the review.[324]	The Commission considers that the objective should be to make forecasting as accurate as is efficient, and then use regulating FCAS to make up any difference. The AEMC's views on this issue are set out in Chapter 6. A discussion of changes to regulating FCAS is set out in Chapter 5.
TasNetworks expressed concern that an approach that excludes regulatory measures that deal with issues in a specific region only could exclude solutions that can be implemented in Tasmania and are not relevant in other parts of the NEM.[325]	The NER establish a framework for all aspects of the power system that is consistent across all NEM jurisdictions, but recognise that each jurisdiction has specific technical characteristics that may need to be accommodated. The AEMC is of the view that regulatory or policy changes should not be implemented in a way that will only address issues that arise at a specific point in time or in a specific jurisdiction. Rather, solutions should be flexible enough to accommodate different circumstances in

322 AEMO, submission to issues paper, p. 5.

323 S&C Electric Company, submission to issues paper, pp. 1-5.

324 Snowy Hydro, submission to issues paper, p. 5.

325 TasNetworks, submission to issues paper, pp. 1-2.

Issue proposed by stakeholder to be included within scope	AEMC response
	different jurisdictions and apply across the whole of the NEM.
Tesla suggested that the AEMC consider whether a change to Chapter 2 or Chapter 5 of the NER to classify battery storage as a separate class of registered participant, or introduce specific energy storage connection requirements, would be beneficial.[326]	While relevant, the AEMC is of the view that these considerations are not directly within the scope of the *Frequency control frameworks review*. Issues relevant to battery storage are being considered through the AEMC's *Coordination of generation and transmission investment review*.[327]
Energy Networks Australia submitted that the issues within scope of the review seemed to be most relevant to DNSPs. It recommended that the AEMC consider the role of TNSPs in more detail, for example in the design of future inertia markets, procurement functions and how distributed energy resources could be utilised to provide support services to both DNSPs and TNSPs.[328]	Noted. The AEMC has sought to expand the consideration of the role of TNSPs in addressing each of the issues within the scope of the review.

326 Ibid., p. 2.

327 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

328 Energy Networks Australia, submission to issues paper, pp. 1-2.

B Related work

The *Frequency control frameworks review* follows, and is being undertaken alongside, a range of other work being carried out in the system security space by the AEMC, the Reliability Panel and AEMO. These projects are summarised in this appendix.

B.1 AEMC projects

The *Frequency control frameworks review* forms part of the AEMC's integrated approach to addressing the challenges involved in maintaining system security and reliability as the NEM undergoes technological transformation. The AEMC's system security and reliability action plan, comprising a number of rule changes and reviews that are either underway or complete, is focused on how the electricity system can be kept in a secure state with enough generation and demand response capability to supply consumer needs, in the context of the changing generation mix in the NEM.

Three projects in the action plan that are most relevant to the review are described in more detail below.

B.1.1 System security market frameworks review

The AEMC initiated the *System security market frameworks review* in July 2016 to explore what changes to the market and regulatory frameworks may be needed to support the ongoing shift towards new generation technologies in the NEM.[329]

The final report of the review, published in June 2017, made nine recommendations for changes to help deliver a more stable and secure supply of electricity. Six of these recommendations, set out below, are measures to provide for better frequency control.

1. Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs).

2. Review the structure of FCAS markets, to consider:

    (a) any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service

    (b) any longer-term options to facilitate co-optimisation between FCAS and inertia provision.

329 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review#

3. Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day.

4. Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.

5. Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.

6. Place an obligation on transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.

Recommendations 1 - 4 on this list are included in the terms of reference for the *Frequency control frameworks review*. In June 2016 AGL submitted a rule change request to the AEMC seeking to implement a mechanism to guide the provision of inertia for market benefits.[330] On 6 February 2018 the AEMC published a final determination to not make a rule on this rule change request in light of the views expressed by stakeholders in submissions and analysis of the benefits of the introduction of an inertia market mechanism. The AEMC has addressed the immediate system security concerns related to inertia and will continue its assessment of the appropriate design of a mechanism to provide additional inertia for market benefit through the *Frequency control frameworks review*.

Recommendation 5 is being considered through the *Generator technical performance standards* rule change request submitted by AEMO.[331]

Recommendation 6 was considered through the *Managing the rate of change of power system frequency* rule change proposed by the South Australian Minister for Mineral Resources and Energy.[332] A final determination and final rule on this rule change request was published on 19 September 2017. The final rule, which will commence on 1 July 2018, places an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.

A summary of progress against these recommendations is provided in Figure B.1.

330 See: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market

331 See: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards#

332 See: http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque

Figure B.1 Progress against recommendations made in *System security market frameworks review*

RECOMMENDATION	STATUS
A STRONGER SYSTEM	
Require network service providers to maintain system strength at generator connection points above agreed minimum levels, and require new generators to 'do no harm' to previously agreed levels of system strength.	Final rule on *Managing power system fault levels* made 19 September 2017.
Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.	Consultation paper on *Generator technical performance standards* rule change published 19 September 2017.
RESISTING FREQUENCY CHANGES	
Require transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services.	Final rule on *Managing the rate of change of power system frequency* made 19 September 2017.
Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum required levels.	Final determination on *Inertia ancillary service market* rule change published 6 February 2018. Further consideration through the *Frequency control frameworks review.*
BETTER FREQUENCY CONTROL	
Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts of this.	For consideration through the *Frequency control frameworks review.*
Review the structure of FCAS markets, to consider: • any drivers for changes to the current arrangements, how to most appropriately incorporate FFR (fast frequency response) services, or alternatively enhancing incentives for FFR services within the current six second contingency service • any longer-term options to facilitate co-optimisation between FCAS and inertia provision.	
Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and leading to increased demand variation within a day	
Consider placing an obligation on all new entrant plant to have fast active power control capabilities.	Consultation paper on *Generator technical performance standards* rule change published 19 September 2017.
FACILITATING THE TRANSFORMATION	
Continue to scope further power system security issues likely to arise from the ongoing transformation of the market, such as the impact on system restart ancillary services of decreasing levels of synchronous generation and the adequacy of current voltage control arrangements.	AEMO to further scope these issues.

B.1.2 Reliability Panel review of the frequency operating standard

The frequency requirements that AEMO must meet are set out in the frequency operating standard, which is defined in the NER and determined by the Reliability Panel.[333]

In March 2017 the AEMC provided terms of reference to the Reliability Panel to conduct a review of the frequency operating standards that apply to Tasmania and to the mainland NEM.[334] The terms of reference included a request for the Panel to give consideration to whether the terminology, standards and settings in the frequency operating standard remain appropriate. The review is being undertaken in two stages:

1. Stage one addressed technical issues and changes arising from the *Emergency frequency control schemes* rule change, which commenced on 6 April 2017.[335] The Reliability Panel published a final determination on stage one on 14 November 2017, which made amendments to the frequency operating standard to include a standard for protected events, a revised requirement relating to multiple contingency events, revised definitions of certain terms and a revised limit for accumulated time error in the mainland.

2. Stage two is intended to consider the components of the frequency operating standard, including the levels of the frequency bands and the time requirements for maintenance and restoration of system frequency. This scope is dependent on the outcomes of the *Frequency control frameworks review*, particularly with respect to any changes to the market and regulatory arrangements relating to primary frequency control and FCAS markets. As a result, the Reliability Panel has suspended further work on stage two of the review until the *Frequency control frameworks review* is further progressed.

B.1.3 Reliability frameworks review

Over the past 18 months, events including load shedding in South Australia and New South Wales, pre-emptive action and announcements from governments, recommendations from the Finkel Panel review, and forecasts from AEMO's Electricity Statement of Opportunities have led to a greater focus on reliability in the NEM. At the same time, the NEM is changing at a rapid pace on both the demand and supply sides. The AEMC is undertaking a review to assess whether the current market and regulatory reliability frameworks remain appropriate in this context.[336]

---

333 For an explanation of the role and responsibilities of the Reliability Panel, see: http://www.aemc.gov.au/About-Us/Panels-committees/Reliability-panel

334 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard#

335 See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

336 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Frameworks-Review#

The AEMC published an interim report on the review in December 2017 to provide an update on progress and the AEMC's preliminary analysis and views. Submissions on the interim report are now closed and are available on the AEMC website. The AEMC intends to publish a directions paper for stakeholder consultation in March 2018.

B.2 External projects

B.2.1 AEMO

The *Frequency control frameworks review* is seeking to identify and develop the changes to market and regulatory arrangements required to address the technical issues highlighted by AEMO. As such, it is being coordinated with the ongoing technical work being undertaken by AEMO on frequency control issues under the terms of the collaboration agreement between AEMO and the AEMC. This includes the work in AEMO's work program on Future Power System Security, which it established to build its understanding of the potential opportunities and challenges in operating a stable and secure power system with less synchronous generation.[337]

Of particular relevance to the *Frequency control frameworks review* is AEMO's ongoing investigation of some of the more immediate issues associated with declining frequency control performance in the NEM.[338] The AEMC is working with AEMO to coordinate the analysis and outcomes of this work with the *Frequency control frameworks review*.

AEMO is also conducting a review of the procedure for determining contribution factors, also known as the causer pays procedure. The procedure describes the calculation of market participant factors, which AEMO uses as the basis for recovering costs associated with procuring regulating FCAS.[339] The review is considering potential improvements to the settings and assumptions used in calculating market participant factors under the causer pays procedure.[340]

B.2.2 Energy Networks Australia

In its submission to the issues paper, Energy Networks Australia proposed that the AEMC consider and advance the findings of the *Electricity network transformation roadmap* to ensure a holistic review of issues as they relate to distributed energy resources.[341]

337 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability

338 See Chapter 5.

339 See section 2.1.2 for an explanation of regulating FCAS.

340 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

341 Energy Networks Australia, submission to issues paper, pp. 1-2.

The *Electricity network transformation roadmap* was developed by Energy Networks Australia in collaboration with the CSIRO to "provide detailed milestones and actions to guide an efficient and timely transformation over the 2017-27 decade."[342] Power system security is one of the roadmap's five areas of "transformational focus", which includes recommended milestones in relation to:

- market frameworks for ancillary services
- power system forecasting.

The AEMC will draw on the analysis and findings of the roadmap and seek to align the recommended milestones of the roadmap with this review, where relevant.

342 See: http://www.energynetworks.com.au/electricity-network-transformation-roadmap

C Overview of frequency control

This appendix provides an overview of:

- power system frequency
- frequency variation.

A more detailed description of these issues can be found in the issues paper for the *Review of the frequency operating standard*,[343] and in the interim and final reports of the *System security market frameworks review*.[344]

C.1 What is power system frequency?

The NEM, like most modern power systems, generates and transfers electricity via an alternating current (AC) power system.[345]

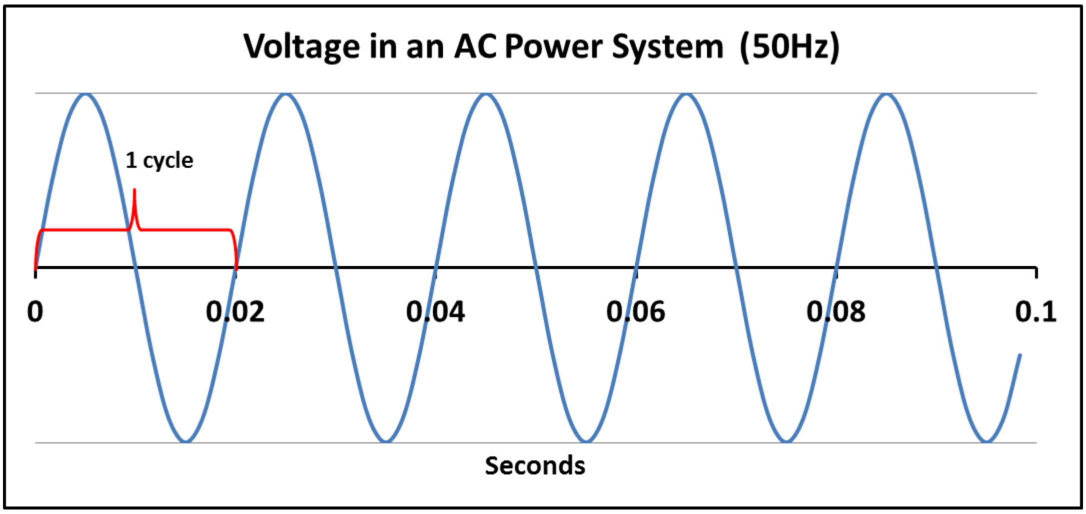
In an AC power system, alternating currents are accompanied (or caused) by alternating voltages. Voltage oscillates between negative and positive charge at a given rate. This can be represented by the following wave diagram, which shows how voltage shifts from positive to negative charge over a specific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

343 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard#

344 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

345 Electrical power can be transferred by means of direct current (DC) or alternating current (AC). In a DC system the direction of current flow is constant, whereas in an AC system the direction of current flow periodically reverses. The power transfer in an AC system occurs through the oscillation of electrons in the transmission and distribution system, rather than through the direct movement or "flow" of electrons.

Figure C.1 Voltage in an AC power system



In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hz.[346]

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

C.2 Frequency variation

C.2.1 What is frequency variation?

The frequency in an operating power system varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise, and vice versa.

This frequency variation is similar to how a car behaves when it begins to climb a hill after driving along a flat road. In order to maintain a constant vehicle speed as the car climbs the hill, the engine power must be increased to balance the increased "load" or the car will slow down. The engine power is increased by depressing the accelerator pedal, which supplies more fuel to the engine to maintain the vehicle speed.

346 Other power systems operate at different standard frequencies. For example, the nominal power system frequency in the United States and Canada is 60 Hz, while Europe and the United Kingdom operate their power systems at 50 Hz.

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

In the majority of situations, the changes in supply and demand that cause frequency variations are such that the corresponding variations in frequency are very small. Household appliances and industrial load being switched on and off are all examples of minor changes in demand happening all the time. The quantity of electricity supplied into the network may also change due to the variable output of wind and solar generation.[347]

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

C.2.2 What are the consequences of frequency variation?

All equipment connected to the power system is designed to operate at or near the nominal frequency of 50Hz. For example, a typical steam turbine can operate continuously at ±1 per cent away from the nominal frequency, or within a range of 49.5-50.5Hz. Most consumer electronic equipment is designed to operate within a tolerance range of ±5 per cent away from the nominal frequency, or 47.5-52.5Hz.

The tolerance of different machines or devices to frequency deviations varies both in terms of the size of a divergence that can be withstood and the length of time that the deviation can be ridden through. Large or lengthy deviations outside of these tolerance limits can increase wear and tear on this equipment, and could have significant impacts on its safety and functional efficiency. For example, steam turbines are generally only designed to withstand short periods of operation outside of its tolerance range, with a practical working limit reached at around ±5 per cent or 47.5-52.5Hz.[348] The turbine may experience damaging vibrations outside this operating frequency range and, if allowed to operate at an excessively high speed, there is risk of a catastrophic equipment failure.

347 In practice, AEMO forecasts the expected demand and the output of variable renewable generation as part of its operation of the wholesale electricity market. Operationally, minor frequency deviation can be a result of actual demand or generation output varying from the demand or generation output as forecast. This forecast error issue has been raised in AEMO's Future Power System Security work program in the following report: AEMO, Visibility of Distributed Energy Resources, January 2017, p. 14.

348 General Electric Company, 1974, Load Shedding, Load Restoration and Generator Protection Using Solid-state and Electromechanical Under-frequency Relays – Section 4 – Protection of steam turbine – generators during abnormal frequency conditions.

As a self-protection mechanism, generation and transmission equipment is designed to disconnect from the power system during periods of prolonged or excessive deviations from the nominal system frequency. However, the disconnection of generation due to low system frequency would worsen the supply-demand imbalance that originally caused the frequency disturbance and potentially lead to a cascading system failure and a major blackout. Controlling frequency is therefore critically important to maintaining a secure and reliable power system.

D Summary of AEMO advice to the *Frequency control frameworks review*

D.1 Primary frequency control during normal operation

The AEMO advice suggests that there are likely to be benefits to the provision of greater levels of primary frequency control and that this is not able to be substituted with an increase in regulating FCAS.

The AEMO advice provides a detailed definition of primary and secondary frequency control and the interaction of the two services in order for AEMO to manage power system frequency during normal operating conditions. The advice notes that there are benefits from a broad distribution of primary frequency control throughout the power system, including increased resilience to non-credible contingency and islanding events.

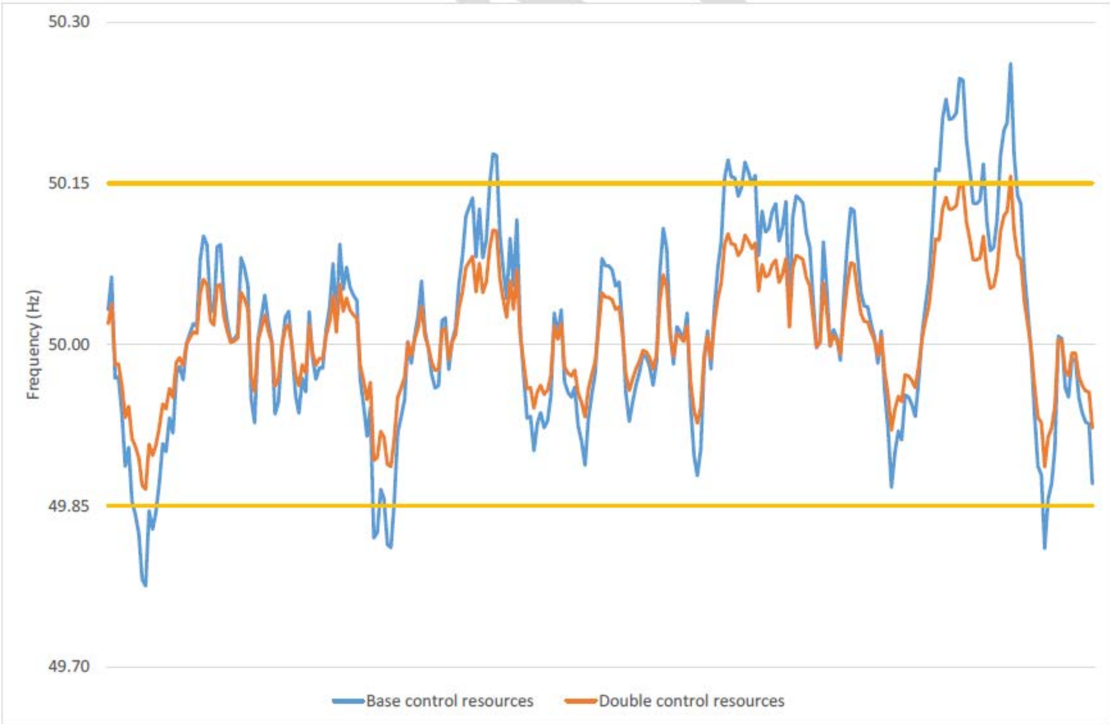
AEMO notes that the current FCAS market design favours global procurement of services. While regional constraints can be enacted, when such constraints bind they can result in reduced competition and substantially higher FCAS prices.

The AEMO advice presents the results of a series of modelling exercises undertaken by AEMO to investigate the interaction of primary and secondary frequency control. This analysis shows that, in order to correct a temporary imbalance between supply and demand, similar amounts of primary and secondary control services are required. However, the amount of primary frequency control that is active in the power system plays an important role in determining the extent of the frequency deviation for a given supply demand imbalance.

The AEMO advice illustrates the impact of additional primary frequency control on the management of random frequency variation within a hypothetical power system model. The model assumes continuous proportional primary response to frequency variation with no dead band and ignores the handover between primary and secondary response. Figure D.1 shows that a doubling of primary response reduces the size of the frequency deviation within this hypothetical system by about 40 per cent. The chart includes an indicative representation of the limits of a normal operating frequency band at 49.85Hz and 50.15Hz and shows how the reduction in frequency deviation drives a significant improvement in containing the frequency within the target range.[349]

349 AEMO, Preliminary advice to the *Frequency control frameworks review*, February 2018.

Figure D.1 Hypothetical impact of extra primary frequency control



Source: AEMO, Preliminary advice to the *Frequency control frameworks review*, February 2018.

The AEMO advice also discusses the impact of additional secondary control in relation to managing variation in system frequency. AEMO's analysis shows that additional secondary response does not reduce the maximum size of the frequency deviation, but may provide a more rapid restoration of frequency to 50Hz following an imbalance in supply and demand.

AEMO's advice also includes a discussion of the impact of the availability of headroom to provide the necessary change in active power that constitutes the frequency response. AEMO notes that in the current system there is normally a reasonable amount of headroom capacity with the scheduled generation fleet. However, the availability of this headroom may decrease during periods of peak or minimum load. AEMO notes that while the availability of headroom may be expected to decline as non-synchronous generation replaces synchronous thermal generation, the current FCAS markets allow AEMO to purchase sufficient headroom to maintain system security.

D.2 Outlook for frequency control in the NEM

AEMO has undertaken a preliminary analysis of the expected availability of generation units that are likely to be available to provide frequency response based on the time of day over the next 16 years. This analysis builds on the system projections prepared for the 2016 National Transmission Network Development Plan and does not consider the availability of non-synchronous generation to provide frequency response.

AEMO's analysis shows that over the next 15 years there is expected to be a drop in the number of large synchronous units online at any point in time, with a 50 per cent reduction in coal units online throughout the day and a similar reduction in gas and hydro units online between 9:00am and 4:00pm due to the impact of solar generation. AEMO expects that this change may halve the availability of frequency response from the traditional suppliers of these services.

AEMO notes that as the availability of frequency response declines the need for frequency response may increase. This increased need for frequency response is expected in order to manage the variability of solar generation, and to a lesser extent wind generation. AEMO state that solar generation can be highly variable over short time periods with generation output shown to change by over 50 per cent of the rated system capacity within as little as 4 seconds. AEMO notes that:[350]

> "Even with advanced forecasting techniques, during the middle of the day, it is reasonable to expect that supply from solar generation may drive more variability in the supply-demand balance."

The quantity of large scale solar generation in the NEM is expected to grow from the current installed capacity of 221MW to 1826MW by January 2019.[351] AEMO has prepared an indicative analysis that projects the need for frequency regulation services in relation to the quantity of wind and solar generation installed in the NEM. The results of this analysis are provided below in Figure D.2.[352]

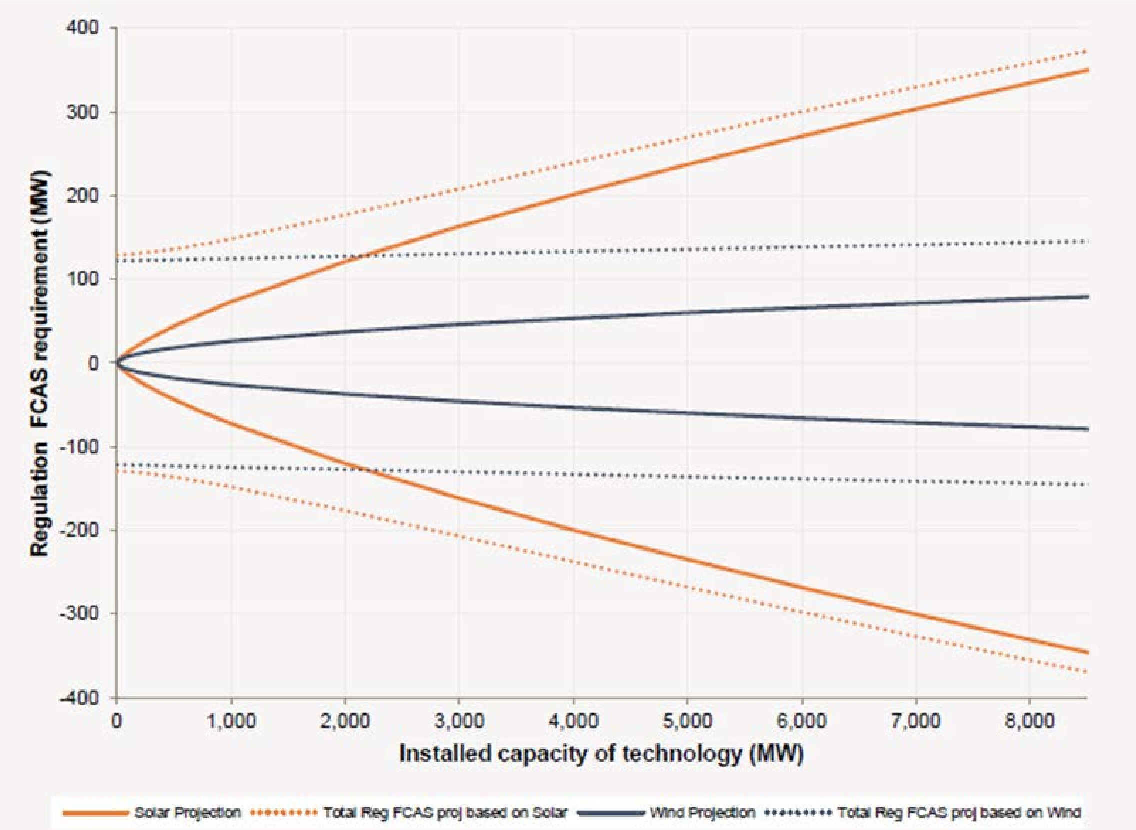
---

350 AEMO, Preliminary advice to the *Frequency control frameworks review*, February 2018.

351 These values are based on committed projects and those currently under construction. AEMO, Generation information, December 2017, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

352 This analysis assumes no significant systematic improvement in solar farm behaviour or forecasting capabilities. It is based on projected movements on the 5-min scale, rather than shorter time scales. The actual requirement for regulation services may vary depending on operational forecast accuracy. See: AEMO, Preliminary advice to the Frequency control frameworks review, February 2018.

Figure D.2 Indicative projection of need for regulation services based on installed solar PV and wind capacity



AEMO's advice notes that given the decrease in availability of traditional forms of FCAS supply and the projected increase in need for frequency responsiveness, new providers of frequency response will be required over the coming years. AEMO notes that while semi-scheduled wind and solar generation are not currently required to have the capability to provide frequency response, the technology to provide such response from wind and solar generation is available.[353]

353 The technical capability for active power control that supports the provision of frequency response is being considered by the Commission through the *Generator technical performance standards* rule change. AEMO notes that the key remaining challenge for accessing this capability is the existence of sufficiently strong financial incentives to drive the investment and operation of solar and wind generation in a manner that provides the required level of frequency response for the secure operation of the NEM.

E Arrangements for generator frequency control settings in the NER

The NER require generators to seek AEMO approval for any change to the frequency settings of their systems.

E.1 Changes to frequency response mode in real time

Rule 4.9 of the NER sets out a number of obligations in relation to real time, power system security-related market operations. Under clause 4.9.4(e) a scheduled or semi scheduled generator cannot "change the frequency response mode of a scheduled generating unit without the prior approval of AEMO." This clause is a civil penalty provision. Frequency response mode is defined in Chapter 10 of the NER 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."

This means that, if a generating unit is operating in frequency response mode, AEMO must be aware of this, and the generator cannot change this without AEMO's approval. In practice, it appears that getting an FCAS enablement from NEMDE is treated (at least by AEMO) as approval to turn on a frequency response mode (if it was off). However, explicit consent is required to turn it off again – that is, not getting an FCAS enablement is not approval to turn it off.

The Commission notes that, during real time dispatch, any change to a generator's frequency operating mode (e.g. as managed by a governor control system) is likely to need AEMO approval.

E.2 Changes to frequency control settings

Schedule 5.2.5.11 of the NER sets out the access standards for generators that must be met in order for them to gain access to the network. The minimum access standard in relation to frequency control is that for a generating system under relatively stable input energy, active power transfer to the power system must not:

1. increase in response to a rise in system frequency; and

2. decrease more than 2 per cent per Hz in response to a fall in system frequency.

In order to meet the automatic access standard in relation to frequency control a generating system must:

1. be capable of automatically reducing its active power transfer to the power system whenever the system frequency exceeds the upper limit of the normal operating frequency band

2. be capable of automatically increasing its active power transfer to the power system whenever the system frequency falls below the lower limit of the normal operating frequency band.

This standard is an AEMO advisory matter.

Clause 5.3.9 of the NER sets out the procedure to be followed by a generator proposing to alter a generating system where that generator already has performance standards that have been approved by the relevant network service provider and AEMO (if it is an AEMO advisory matter). Clauses 5.3.9(a)-(b) of the NER require that a generator proposing to alter a connected generating system or a generating system for which performance standards have been previously accepted by AEMO in a manner that will "affect the performance of the generating system relative to any of the technical requirements set out in clauses S5.2.5…" must, submit to AEMO and the network service provider:

- a description of the proposed alteration and the implementation timetable
- details of the generating unit design data and setting data in accordance with the Generating System Model Guidelines, Generating System Design Data Sheet or Generating System Setting Data Sheet
- the proposed amendments to the applicable automatic or negotiated access standard.

Clause 5.3.9(d) lists the proposed alteration to equipment that is taken to affect the performance of the generating system and necessitate a proposal for alteration. This explicitly includes changes to the governor control system in relation to (amongst other things) frequency control.

Under clause 5.3.9, when a generator proposes to alter a generating system for which performance standards have previously been accepted by AEMO, the network service provider and the generator (and AEMO if it is an AEMO advisory matter) will negotiate the changes. Once agreed and approved, these changes will be lead to an amendment to the connection agreement. The access standards in relation to frequency as set out in cl S5.2.5.11 are an AEMO advisory matter, and therefore changes to them require AEMO approval. AEMO must approve a change that is compliant with the automatic access standard, including in relation to frequency as set out in cl S5.2.5.11.

The Commission therefore notes that under the NER, any change to a generating unit's governor settings would require approval from the network service provider and AEMO.

F The degradation of frequency performance during normal operation

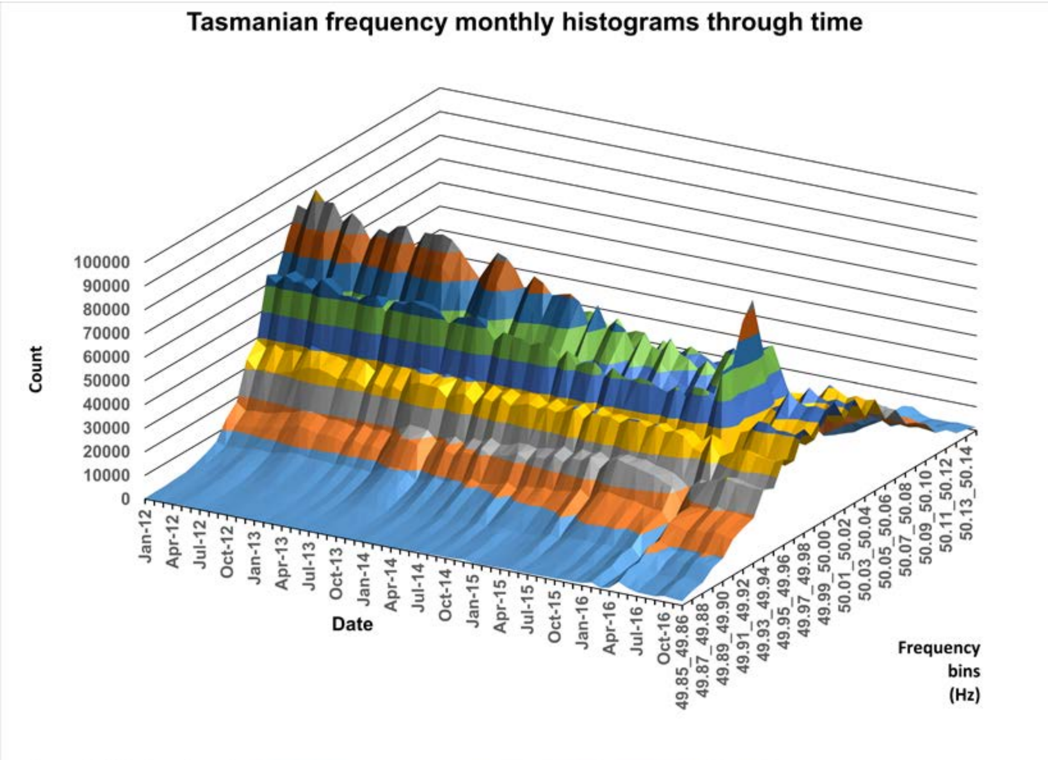
This appendix provides further detail on the evidence of the degradation of frequency performance during normal operation, a summary of the findings from DIgSILENTs investigation of this degradation and an explanation of the role and history of governor response in the NEM.

F.1 Evidence of degradation and AEMO's engagement of DIgSILENT

The Commission is aware that the frequency performance of the power system has declined in recent times. Specifically, there is some evidence that the power system frequency increasingly operates further away from the nominal frequency of 50 Hz than has historically been the case.

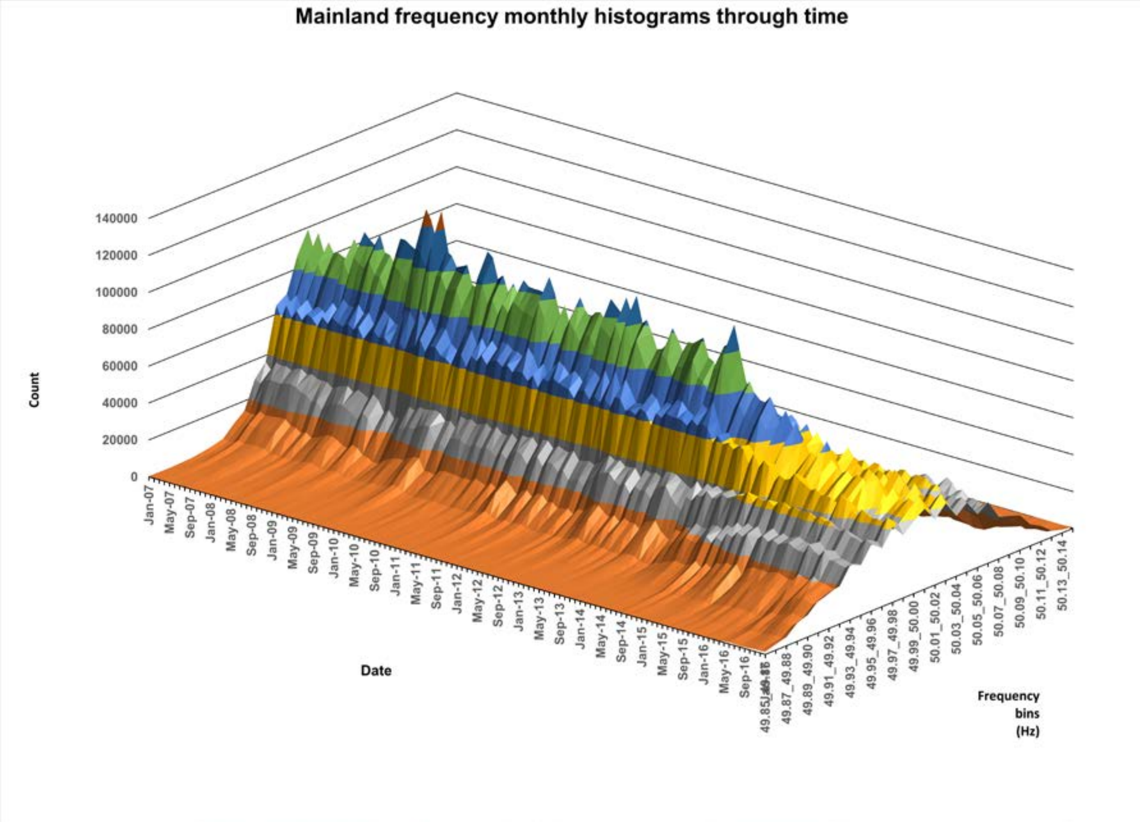
In May 2017 AEMO published frequency distribution charts showing the long term trend between 2012 and 2017 for Tasmania (Figure F.1). In November 2017 AEMO published an updated chart showing the long term trend for the between 2007 and 2017 for the NEM mainland (Figure F.2). These charts reinforce the long term trend of a "flattening" of the frequency distribution within the normal operating frequency band during normal power system operation.

Figure F.1 Tasmania frequency distribution – 2012-2017



Source: AEMO, 3 May 2017, ASTAG – Meeting Pack – 3 May 2017, Presentation 2 - Frequency Performance.

Figure F.2 NEM mainland frequency distribution – 2007-2017



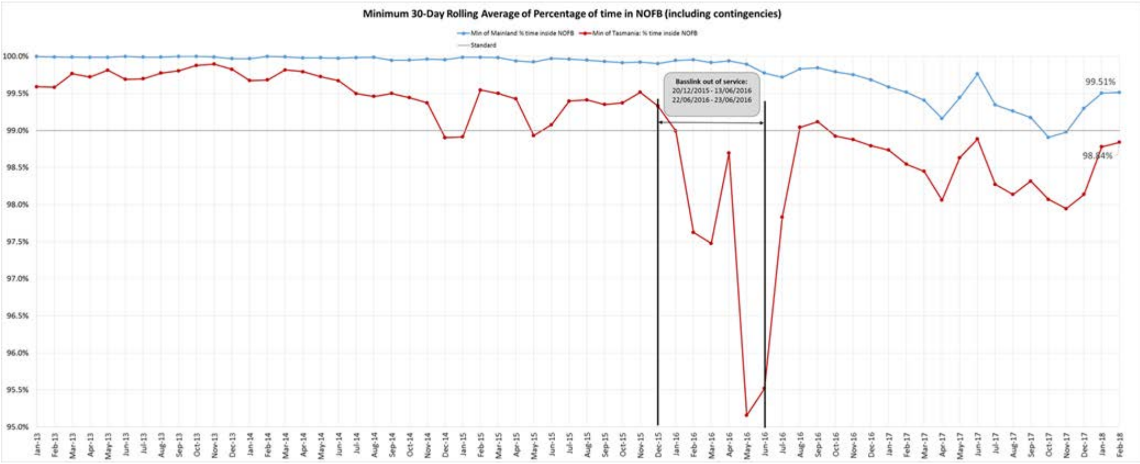
Source: AEMO, ASTAG – Meeting Pack – 28 November 2017, Presentation 5 – Regulation FCAS Performance.

AEMO's most recent frequency monitoring reports provides a more detailed picture of frequency performance in the NEM over the past three years.[354] Figure F.3 displays the performance of the NEM relative to the normal operating frequency band(49.85Hz - 50.15Hz) from January 2013 through to February 2018.[355]

354 AEMO, 2017, Frequency monitoring – Three year historical trends, 9 August 2017; AEMO, 2018, Frequency monitoring and time error reporting - 4th quarter 2017, March 2018.

355 AEMO has been producing frequency reports voluntarily on an ad hoc basis. However, between 2011 and 2014, AEMO published frequency and time deviation monitoring reports on a quarterly basis. The issue of frequency monitoring and reporting is addressed further in Chapter 6.

Figure F.3 NEM mainland and Tasmanian frequency performance to February 2018



Source: AEMO, February 2018.

Figure F.3 shows a decline in frequency performance in both the mainland and Tasmania from September 2016 through to April 2017, followed by an improvement in frequency performance in May and June 2017. The degradation of frequency performance during early 2017 was related to settings within AEMO's AGC system which were subsequently changed to correct the frequency performance.[356] These changes are likely to have contributed to the improvement in frequency performance seen since April 2017. Frequency performance during normal operation declined again from June 2017 through to October 2017 before improving through to February 2018.

The frequency operating standard requires that, except as a result of a contingency event or a load event, system frequency should not exceed the applicable normal operating frequency excursion band and should not exceed the applicable normal operating frequency band for more than five minutes on any occasion and not for more than 1 per cent of the time over any 30-day period.

The frequency in the mainland NEM exceeded the normal operating frequency band for more than 1 per cent of the time in the 30-day periods of October and November 2017, including time during contingency events. However, the mainland frequency did not exceed the normal operating frequency band for more than 1 per cent of the time over any 30-day periods when contingency events are excluded.[357]

The frequency in the Tasmanian power system exceeded the normal operating frequency band for more than 1 per cent of the time from February 2016 to February 2018, with the exception of August and September 2016, including time during contingency events. When time during contingency events is excluded, the frequency in the Tasmanian power system exceeded the normal operating frequency band for more than 1 per cent of the time from February 2016 to July 2016 (related to the

356 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017

357 AEMO, 2018, Frequency monitoring and time error reporting - 4th quarter 2017, March 2018.

Basslink outage) and from February 2017 to December 2017 with the exception of May and June 2017.[358]

F.2 DIgSILENT's findings

F.2.1 Evidence

The preliminary results of the DIgSILENT analysis were presented to the ASTAG on 9 August 2017. AEMO published the report itself on 21 October 2017.

The Commission understands that the DIgSILENT analysis confirmed that the root cause of the long term degradation of frequency performance is a reduction of primary frequency response within the NEM during normal operation.

DIgSILENT's analysis shows that there has been a very significant decline in the amount of governor response being provided within the normal operating frequency band since the introduction of the FCAS markets and the removal of the compulsory provision of governor response. It concludes that this has had an adverse impact on the performance of frequency regulation within the normal operating frequency band.[359]

This reduction of primary frequency response during normal operation is understood to have taken place gradually over a period of years through generators putting in place changes to their generator control systems including:[360]

- Widening their governor dead band settings out to between ±0.1 Hz and ±0.15 Hz. The effect of this is that the generators that have made this change are unresponsive to frequency changes until the frequency drops below 49.9 Hz – 49.85 Hz or rises above 50.1 – 50.15 Hz.
- Upgrading of older mechanical governors to newer digital control systems. These digital governor control systems enable a generator to easily change the frequency response mode of the generator, and the governor settings such as the dead band and droop characteristics.
- Where it is more difficult or costly to change their governor settings and uneconomic to upgrade to digital systems, generators have installed secondary control systems to dampen the primary governor response of their generating units, in favour of maintaining alignment of generator output with dispatch targets. These secondary controllers essentially expand the effective dead band for these generating units to ±0.15 Hz, in line with the normal operating frequency band of 49.85 Hz to 50.15 Hz.

358 Ibid.

359 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 6.

360 Ibid., pp 29, 42.

The net result of these changes to generator control systems is a reduction in the level of primary frequency control that contributes to maintaining the power system frequency within the normal operating frequency band (49.85 Hz to 50.15 Hz).

The DIgSILENT report noted that AEMO's AGC system is not designed to be able to make up for the reduction in primary frequency control.[361] The Commission understands that the AGC system is capable of responding to generation and demand imbalance within approximately 30 seconds whereas primary frequency control is able to respond almost immediately to frequency deviations based on local frequency measurement and automatic response through the generator governor control systems.

DIgSILENT also reported on its preliminary assessment of a small number of slow unstable frequency oscillations that have occurred recently within the NEM power system.[362] DIgSILENT confirmed the occurrence of two oscillatory events, one on 28 October 2016 and the other on 10 February 2017. The event on 10 February 2017 followed the failure of a generating unit at the Tallawara power station. The event on 28 October 2016 was not associated with any identified contingency event. Both events showed oscillations of frequency with a wave period of approximately 25 seconds that persisted for between 5 and 10 minutes. DIgSILENT noted that "further work would be required to examine the oscillatory events in detail to ascertain their cause or causes."[363]

F.2.2 Possible causes of the deterioration

DIgSILENT identified a number of drivers that are contributing to the decline in primary frequency control within the NEM including:

- Generators who provide primary frequency control incur increased fuel and maintenance costs as a result of this mode of operation. As this service is not mandatory, nor are the costs of the service reimbursed, there is no incentive for generators to provide primary frequency control.
- Many market participants believe that their contribution factors for the recovery of regulating FCAS costs can be reduced when their generator governors are set up to be unresponsive to frequency.[364]

---

361 The AGC is designed as a secondary frequency control system that centrally measures the power system frequency and sends out "raise" or "lower" signals to the registered generators and loads that are dispatched to provide FCAS to correct the small frequency deviations.

362 These oscillatory events were identified by Pacific Hydro and reported in the Pacific Hydro submission to the Independent Review into the Future Security of the National Electricity Market, March 2017.

363 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, pp. 34-35, 47.

364 The causer pays procedure sets out the mechanism by which AEMO recovers the cost of regulating FCAS services from market participants. Regulation service 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 generator's actual output or, in the case of a scheduled load,

- Some market participants noted compliance with their rules obligations was more difficult if they operated with governors that responded to frequency changes. This includes compliance with dispatch targets, compliance with FCAS offers and compliance with generator performance standards.

The DIgSILENT analysis identified a number of other contributing factors to the degradation in frequency performance in the NEM, including:

- An increase in contrary frequency control behaviour. Contrary frequency control has been found to occur due to a number of situations where the AGC instruction to generators may run contrary to the recovery of a frequency deviation. For example where the frequency is above 50 Hz and the AGC system is sending out "raise" signals to generators enabled to provide regulating FCAS. One of the causes of this phenomenon is time error correction, which is used to reduce accumulated time error that builds up due to deviations in the power system frequency.

- A reduction in load frequency response due to the increase of industrial loads supplied by variable speed drives. The power demand of these machines is independent of system frequency due to the fact that they are connected to the power system behind electronic inverters rather than traditional "direct on-line" connection.[365]

- A reduction in system inertia in the NEM due to the increase of inverter supplied generation, such as wind power and solar PV, and the retirement of aging large thermal generating units.

F.3 What is governor response and what is its purpose?

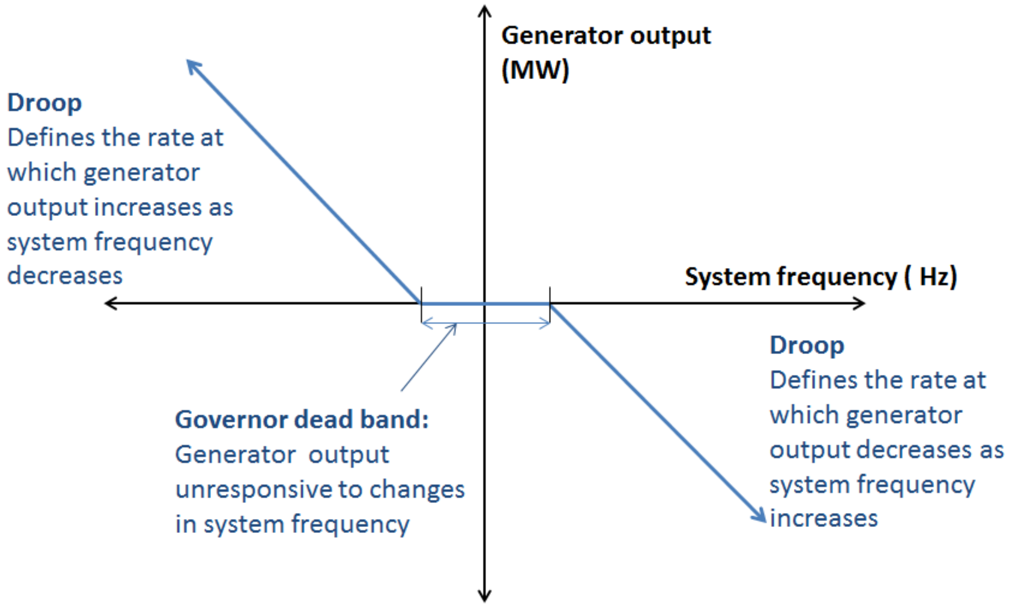
A governor is a part of a generator control system that regulates the electrical output of a generating unit or generating system. In the context of frequency control, governors can be used to respond to frequency changes through changes in generating output. Governors can be enabled to be automatically responsive to changes in the power system frequency outside of a pre-determined dead band. The dead band specifies the frequency range within which the governor is unresponsive to power system frequency changes, and within which the power output from the generator is kept steady, as shown in Figure F.4.

their actual demand, differs from the targets assigned by the NEMDE. A further discussion of causer pays arrangements is set out in section 5.3.2.

365 Load frequency response is a phenomena associated with the operation of synchronous motors where the power demand of the motor decreases due to a drop in system frequency and conversely the power demand increases in response to an increase in system frequency. This helps to stabilize system frequency changes by acting to balance supply and demand in the power system. Inverter connected machines, such as those connected via variable speed drives, do not necessarily have this operational characteristic and are more likely to have demands that are unresponsive to frequency, unless they are expressly programmed to be responsive to system frequency.

Droop is an indication of the change in generator output for a given change in power system frequency. Given a fall in power system frequency, the droop setting refers to the percentage frequency change that will result in the output of a generator increasing to 100 per cent of its rated capacity. For example given a 100 MW generator with a droop setting of 5 per cent and assuming that the generator is operating with sufficient headroom, a fall in power system frequency of 0.05 Hz or (0.1 per cent of 50 Hz) will result in an increase of power output from the generator of 2MW. Similarly following an increase of power system frequency of 0.05 Hz the same generator would decrease its power output by 2MW.

Figure F.4 Generator frequency response and the governor dead band



In the NEM, generator governor response is responsible for the delivery of contingency FCAS from generators that are enabled via the FCAS markets. This service is activated at frequency set-points outside the normal operating frequency band (49.85 Hz to 50.15 Hz). Generators that are not enabled to provide contingency FCAS, are not required to provide a primary response to a change in the power system frequency.[366] The response of a generating system to frequency changes is specified in the generator performance standards that form part of a generator's connection agreement. A summary of the generator performance standards that apply for frequency control is provided in section 2.1.3.

F.4 History of governor response in the NEM

At the start of the NEM, in 1999, ancillary services were procured under the National Electricity Code through a tender process and long term contracts between

366 Schedule 5.2.5.11 of the NER specifies the minimum and automatic performance standards that apply to how a generating system must respond to changes in power system frequency.

NEMMCO[367] and service providers.[368] These contracts ensured the availability of the service (for instance, by ensuring that sufficient generators had "headroom" to provide a response above their dispatch targets), but all generators were mandated to provide a governor response to the extent that they were able to.

Following the Ancillary Service Review undertaken by NEMMCO in 1999, the ACCC provided authorisation for the creation of 8 ancillary service spot markets for the enablement of regulating and contingency FCAS.[369] In 2003, the requirements for mandatory generator governor response included in S5.2.6.4 of the National Electricity Code was removed and replaced with S5.2.5.11, which set out the revised generator technical standards for frequency control.[370]

The removal of the requirement for mandatory response was not an inherent result of introducing FCAS markets - the spot markets for enablement simply replaced the previous contracting approach. It would have been possible to continue to impose the mandatory response obligation. However, in its review, NEMMCO recommended that this obligation be removed. The justification for this was that mandatory provision represented a "hidden subsidy" and that "governor capability should be fully paid for under the FCAS arrangements proposed".[371]

When the NEM began operation in 1998, all generating units over 100MW were obliged to have governors that responded to changes in system frequency outside of specified, relatively tight dead bands.

Prior to November 2003 the National Electricity Code included a requirement mandating that generators have an operational governor system that automatically responded to frequency. This "governor system" requirement, set out in schedule 5.2.6.4 of the code, was removed in November 2003 and replaced with automatic and minimum access standards that require generators to have the capability to respond to frequency disturbances.[372]

The mandatory governor system requirement applied to all generating units with a rated capacity of 100MW and above. The requirement specified key performance criteria relating to the governor responses, which are set out in Box F.1.[373]

---

367 The National Electricity Market Management Company (NEMMCO) was a predecessor to AEMO.

368 NEMMCO, Ancillary Service Review - Recommendations, Final Report, 15 October 1999, p. i.

369 ACCC, National Electricity Code – Ancillary services amendments – determination, 11 July 2001 p.38.

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

371 Intelligent Energy Systems, Who should pay for ancillary services?, A project commissioned by the NEMMCO ancillary services reference group, Final report, July 1999, p. 48.

372 NECA, 2003, Technical standards code changes – Gazette notice, S5.2.11, 27 March 2003 The automatic and minimum access standards set out in S5.2.5.11 of the code version 1.0, amendment 7.7 form the basis of the current S5.2.5.11 in the NER.

373 Ibid., S5.2.6.4.

Box F.1 Technical performance requirements of governor systems under the National Electricity Code prior to 16 November 2003

- The response of the generating unit to system frequency excursion should be capable of:
  - achieving an increase in the generating unit's active power output of 2% per 0.1 Hz reduction in system frequency for any initial output up to 85% of rated output
  - a reduction in the generating unit's active power output of 2% per 0.1 Hz increase in system frequency provided the latter does not require operation below technical minimum.
- Generating units must be capable of achieving an increase in output of at least 5% of their rating for operation below 85% of output. For operation above 85% of rated load, the required increase will be reduced linearly with generating unit output from 5% to zero at rated load. The generating unit will not be required to increase output above rated load.
- Generating units must be capable of achieving a decrease in output of at least 10% of their rating for operation at all levels above their technical minimum loading level as advised in the registered bid and offer data.
- The dead band of a generating unit (being the sum of the increase and the decrease in system frequency before a measurable change in the generating unit's active power output occurs) must be less than 0.1 Hz.
- For any frequency disturbance a generating unit must be capable of achieving at least 90% of the maximum response to power generation expected according to the droop characteristic within 60 seconds and sustain the response for a minimum of 30 seconds.
- When a generating unit is operating in a mode such that it is insensitive to frequency variations (including pressure control or turbine follower for a thermal generator), the Generator must apply a dead band of not greater than 0.25 Hz to ensure that the generating unit will respond for frequency excursions outside the normal operating frequency band.

G International case studies

G.1 Frequency control services in the United Kingdom

Operators of the UK national grid have an obligation under the grid code to control frequency at 50Hz ±1% (49.5 – 50.5Hz), but also aim for a narrower range of 49.8 – 50.2Hz during normal operation. The UK national grid procures a range of frequency response services to manage system frequency, these services are described below:

- **Mandatory frequency response (MFR)**

  In the UK grid, MFR is an automatic change in active power output via a generator governor system in response to a frequency change outside of a set frequency dead band. This response is proportional to the change in frequency (known as 'droop response', which must be in the range of 3 – 5%) and the deadband must not be wider than ±0.015Hz.[374] The UK grid code sets out three types of frequency response that can be provided to satisfy the MFR obligation.[375]

  1. Primary response - provision of additional active power (or a decrease in demand) within 10 seconds after an event and can be sustained for a further 20 seconds

  2. Secondary response - provision of additional active power (or decrease in active power demand) within 30 seconds after an event and can be sustained for a further 30 minutes.

  3. High frequency response - the reduction in active power within 10 seconds after an event and sustained indefinitely.

  The capability to provide MFR is a condition of connection for all generators over a certain registered capacity, depending on the transmission network. The threshold for MFR capability is 100MW for connection to the National Grid, 10MW for Scottish Hydro Electricity Transmission or 30MW for Scottish Power.[376]

  When a generating unit is built or modified, its capability to provide MFR is tested and documented through a contract known as a mandatory service agreement.[377] The grid operator, National Grid, may then instruct generators to operate in a frequency sensitive mode to provide frequency response in accordance with their ancillary service agreement. Generators who are instructed to operate in a frequency sensitive mode are compensated through a

374 UK Grid Code, CC.6.3.7(c)(iii)

375 UK Grid Code, GD.1.

376 National Grid, Mandatory Frequency Response, version 1.1.

377 National Grid, Connection and Use of System Code, clause 1.3.3.

generator-nominated holding payment (in £/hour) for being available to provide MFR and a response energy payment (£/MWh) for the amount of energy delivered through provision of the frequency response service.[378]

- **Firm frequency response**

  The firm frequency response mechanism allows other providers of frequency response to tender for the provision of primary, secondary and high frequency response services as an alternative to the enablement of mandatory frequency response. The services may be dynamic - continuous services or non-dynamic - switched response services. Offers must be a minimum of 1MW and meet a range of technical requirements.[379]

  Providers of firm frequency response respond to a signal from the National Grid operator to operate their plant in a frequency sensitive mode. Service providers are procured by National Grid through a monthly tender that dispatches eligible providers by least cost. Providers are compensated through an availability payment (in £/hour) for being available to provide MFR and a response energy payment (£/MWh) for the amount of energy delivered through provision of the frequency response.[380]

- **Enhanced frequency response**

  Enhanced frequency response is a service tendered by the system operator to provide frequency response in 1 second or less from providers with at least 1MW response and a maximum ±0.1 Hz dead band.[381] In July 2016 the National Grid ran a one-off tender for enhanced frequency response which resulted in 200 MW of capacity procured from 8 providers, mostly using battery storage.[382] Providers are compensated through a single availability payment (£/MW/h) for the hours tendered to make the service available. Providers do not receive additional payment for dispatching energy as part of the service. It is anticipated that EFR will be incorporated into the other UK frequency response markets.[383]

378 National Grid, Connection and Use of System Code, clause 4.1.3.8.

379 National Grid, Firm Frequency Response (FFR) - Interactive Guidance, 19 December 2017, pp. 7,11.

380 National Grid, Connection and Use of System Code, clause 4.1.3.8.

381 National Grid, Enhanced Frequency Response: Questions and Answers, 29 March 2016.

382 National Grid, Enhanced Frequency Response Market Information Report, 26 August 2016.

383 See: https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/enhanced-frequency-response-efr?how-to-participate Accessed 6 March 2018.

G.2 Frequency control services in New Zealand

The system operator in New Zealand, Transpower, aims to control frequency in a normal band of 49.8 – 50.2 Hz. In addition to the dispatch of generation to meet demand, frequency in the New Zealand power system is controlled in two ways:[384]

- **Automatic generator governor response**

  Generators with governors automatically react to variations in frequency by increasing or decreasing their active power output from their dispatch set point. Governor response is currently an unpaid, mandatory service in NZ for generators of 30 MW or greater, as well as owners of HVDC lines.[385] Generators with governors, are expected to have a droop response that can be set in the range of 0 – 7%. The NZ grid code does not mandate a dead band for governors as the dead band can be inherent in the physical characteristics of a generator. The NZ grid is also experiencing a reduction in governor response over recent years and is in the process of investigating whether it is appropriate to establish an incentive payment or procurement mechanism for the provision of governor response.[386]

- **Multiple frequency keeping (MFK) ancillary service**

  Generators providing this service change their output in response to a control signal from the system operator, in the same way that generators providing regulation FCAS in Australia respond to an AGC signal from AEMO. Providers of MFK must be able to adjust their output by at least ±4 MW, known as the minimum frequency keeping band. MFK providers can be compensated in one or more of the following ways:

  — providers submit bids for a response price paid for each half hour that the service is provided, with providers dispatched in order of increasing price

  — dispatched providers receive the energy market price for energy generated

  — providers may be entitled to additional payment if their energy dispatch is constrained by the system operator.

MFK is slower acting than governor response, but reduces the amount of work required from governor response providers. The system operator also procures back-up Single Frequency Keeping, which is a form of governor response at a

384 NZ Electricity Authority, Normal Frequency Management Strategic Review: Information paper, March 2017.

385 NZ Grid Code ('The Code'), clause 8.17.

386 NZ Electricity Authority, Normal Frequency Management Strategic Review: Information paper, March 2017, p. 25.

generator that activates when MFK is not functioning properly. Providers of this service are compensated with a monthly availability fee.[387]

The New Zealand Electricity Authority is currently undertaking a review of how frequency is managed, including obligations of generators, a proposed national market for frequency control, as well as cost allocation and the dispatch process.[388]

G.3 Frequency control services in Ireland

EirGrid manage and operate the transmission grid across the Island of Ireland. EirGrid is currently delivering a multi-year programme, 'Delivering a secure, sustainable electricity system' known as the DS3 programme. The development of system services for frequency control form a central part of the DS3 programme.

In Ireland frequency is controlled to 50Hz with a normal operational frequency range of 49.8 Hz to 50.2 Hz.

In the Irish electricity grid, primary frequency control is provided by services that automatically respond within a period of 2 - 15 seconds following a frequency deviation outside a given range. EirGrid procures primary frequency control under two separate market service categories:[389]

- **Fast frequency rFFR)** –the additional increase in MW output from a unit or a reduction in demand following a frequency event that is available within two seconds of the start of the event and sustainable for at least eight seconds afterwards

- **Primary operating reserve (POR)** - the additional MW output (and/or reduction in demand) that is available within 5 seconds of the start of the event and sustainable for 15 seconds afterwards. It is mandatory for conventional generation to provide 5% of their maximum capacity as POR. From 2018 onwards other technologies can begin to provide POR such as batteries, emulated wind inertia and demand response.

In addition to these primary frequency control services, EirGrid procures the following secondary and tertiary frequency control services that operate between 15 seconds and 20 minutes following a frequency deviation outside a given range:

- **Secondary operating reserve (SOR)** - the additional MW output (and/or reduction in demand) which is fully available and sustainable over the period from 15 to 90 seconds following an event. It is mandatory for conventional generation to provide 5% of their maximum capacity as SOR.

387 Ibid. p.17.

388 Ibid.

389 EirGrid - SONI, Consultation on DS3 System Services Enduring Scalar Design - DS3 System Services Implementation Project, 4 July 2017, p. 2.

- **Tertiary operating reserve 1 (TOR 1)** - the additional MW output (and/or reduction in demand) which is fully available and sustainable over the period from 90 seconds to 5 minutes following an event. It is mandatory for conventional generation to provide 8% of their maximum capacity as tertiary operating reserve.

- **Tertiary operating reserve 2 (TOR 2) -** the additional MW output (and/or reduction in demand) which is fully available and sustainable over the period from 5 minutes to 20 minutes following an event. It is mandatory for conventional generation to provide 8% of their maximum capacity as tertiary operating reserve.

The trigger points for these system services are based on their response time. The value that the frequency trigger is set at is based on the agreed capability of a unit, together with system requirements. The delivery of these services is measured from local SCADA data or Phasor Monitoring Units in the case of conventional generators/wind farms. EirGrid does not operate an AGC enabled system.

Frequency control services in Ireland are not co-optimised in the same way they are in the Australian market. However, in real-time operation, the costs of providing reserves are considered when dispatching for reserve availability.

The grid code, which establishes the rules governing the transmission system, do not oblige service providers to deliver the new system services. However, through the DS3 System Services arrangements, the standards to which service providers will offer these on a commercial basis are being developed.

Arrangements for procurement and incentive payments

The implementation of the DS3 System Services arrangements is divided into two phases - interim arrangements and enduring arrangements. During the interim period (until 2019 at the earliest), the TSOs will contract for services with all eligible providers, who will be paid at a rate, approved by the regulatory authorities, for the volume of services they are able to deliver in each trading period. The enduring arrangements will deliver competitive procurement, where appropriate. In the interim however a tariff will be applied to services where there is insufficient competition.

In future, the arrangements for procurement and payment for service will include:

- **Volume uncapped -** All service providers who pass technical qualification will receive a contract in respect of the service(s) for which they have qualified. Providing units will only tender based on their technical capability, not on price, as a regulated tariff rate will be paid for the provision of each service.

- **Volume capped -** It is proposed that volume capped procurement will apply to FFR, POR, SOR, TOR1 and TOR2 where the providing units providing the services are classified as “high availability” technologies, i.e. they provide services with a high level of availability that is not limited by their position in the energy market

The agreed capability of a unit, together with system requirements, is to determine at what frequency set point a unit is operationally placed at. The value that the frequency trigger is set at will not affect payment. Payment will be based on the frequency trigger at which the provider is capable and willing to provide the response. It is proposed that payment for regulated arrangements will be based on tariffs multiplied by different types of scalars (performance/product/scarcity/volume) and by available volume.

It is proposed to introduce trigger scalars as part of a product scalar. The value of the trigger scalar applicable to each unit is to be derived from the unit's contracted capability and willingness to provide the FFR, POR, SOR and/or TOR1 service at a specified frequency set point. This will be agreed during the procurement process and form the basis for settlement. Performance monitoring mechanisms will assess whether the unit responded by its contracted frequency set point, with discount factors to apply in the form of a reduced performance scalar if the contracted set point is demonstrated not to have been met.[390]

G.4 Frequency control services in Texas

The Electricity Reliability Council of Texas (ERCOT) operates a day-ahead market through which ancillary services are co-optimized along with the provision of energy. Each market participant has an ancillary services obligation based on its load relative to total ERCOT load. This is referred to as load ration share (LRS). Market participants may self-schedule ancillary services or purchase them through the ERCOT markets. Providers are paid a day-ahead price and/or a deployment price if deployed by ERCOT on the operating day. If there are no deployments providers still, receive a capacity payment.

ERCOT controls the frequency to 60Hz. Under normal conditions, the frequency in ERCOT varies between 59.97 and 60.03 Hz. ERCOT requires a maximum dead band of 0.017 Hz on all generators, with the exception of those steam or hydro units with mechanical governors.[391]

ERCOT controls frequency through utilisation of the following services:[392]

- **Regulation reserves** are comprised of regulation-up and regulation-down services and are capacity that responds every four seconds, either increasing or decreasing as necessary to fill the gap between supply and demand. They commence response in 4-6 seconds, achieve full response in 5 minutes and are sustained for 1 hour. Regulation reserves are deployed based on 4-second automated generation control (AGC) signals.

390 Ibid., p.21.

391 ERCOT, ERCOT fundamentals manual, p. 371.

392 ERCOT, ERCOT Concept Paper - Future Ancillary Services in ERCOT, Electric Reliability Council of Texas, 27 September 2013.

- **Responsive reserves (RRS)** ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity.[393] RRS commence response in 0.5 seconds, achieves full response in 16 seconds and are sustained for 1 hour. RRS are deployed:
  - by automatic generation action as a result of a significant frequency deviation
  - through use of an automatic signal and a dispatch instruction
  - by dispatch instructions from load acting as a resource via an electronic messaging system to providers.
- **Non-spinning reserves** are provided from slower responding generation capacity, and can be deployed alone, or to restore responsive reserve capacity. Non-spinning reserves commence response in 5 minutes, achieve full response in 30 minutes and are sustained for 1 hour.

Primary frequency response

Primary Frequency Response (PFR) is currently included as part of RRS and is defined as the instantaneous proportional increase or decrease in real power output provided by a resource in response to system frequency deviations. This response is in the direction that stabilizes frequency.

In April 2014, the United States federal energy regulatory commission (FERC) approved the North American Electric Reliability Corporation (NERC) Regional Standard BAL-001-TRE-1 to improve frequency performance in the ERCOT region. It mandated governor deadband and droop settings and also introduced compliance mechanisms for evaluating quality of PFR within the ERCOT transmission region. This standard became fully effective in October 2016.[394]

The standard requires that a generator droop setting should not exceed 5% and that all resources with PFR responsibility should maintain a maximum deadband setting of +/- 0.034 Hz for steam and hydro generators with mechanical governors or +/- 0.017 Hz for all other generating facilities. The standard introduces a mandatory obligation that each generator must operate each unit with the governor in service and responsive to frequency when it is online and available for dispatch, unless the generator has a valid reason not to. Wind and solar resources are also required to provide PFR.[395]

Under the standard, two PFR performance measures are calculated: initial and sustained. The initial PFR performance measures the actual response compared to the expected response in the period from 20 to 52 seconds after the start of a frequency event. The sustained PFR performance measures the best actual response between 46

393 The trigger point for automatic load frequency control deployment for online generation resources and controllable load resources for a low frequency event is 59.91Hz.

394 NERC, BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region, 16 April 2014.

395 Ibid. p. 3.

and 60 seconds after the event compared to the expected response based on the system frequency at a point 46 seconds after the event. Each generator must maintain a 12 month rolling average PFR score of 75% or higher. PFR scores are based on data collected from generators. These arrangements do not include any payments for providing a PFR service.[396]

Federal Energy Regulatory Commission (FERC) primary frequency response rule change 2018

On 15 February 2018, the FERC issued a notice of a final rule to revise the Commission's regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of connection. The final determination also recognises the ERCOT regional standard for primary frequency control, Regional Standard BAL-001-TRE-1 as mandatory and enforceable. [397]

The final rule includes modifications that require all newly connecting generators to install a governor or equivalent controls with the capability of operating with a maximum 5 percent droop and ±0.036 Hz deadband. The droop characteristic shall be based on the nameplate capacity of the small/large generating facility, and shall be linear in the range of 59 to 61 Hz. The deadband parameter shall be the range of frequencies above and below 60 Hz in which the governor or equivalent controls are not expected to adjust the small/large generating facility's real power output in response to frequency deviations.[398]

396 ERCOT, Demonstration of PFR Improvement, September 2017.

397 United States of America - Federal Energy Regulatory Commission, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response - Final Rule, 15 February 2018.

398 Ibid.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generator control
ASTAG	Ancillary Services Technical Advisory Group
Commission	(see AEMC)
DNSP	Distribution network service provider
FCAS	Frequency control ancillary service
FFR	Fast frequency response
FI	Frequency indicator
MASS	Market ancillary services specification
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National electricity objective
NER	National Electricity Rules
RoCoF	Rate of change of frequency
TNSP	Transmission network service provider