REVIEW

Australian Energy Market Commission

FINAL REPORT

FREQUENCY CONTROL FRAMEWORKS REVIEW

26 JULY 2018

INQUIRIES

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ABOUT THE AEMC

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

SUMMARY

1 This report highlights several issues that will need to be addressed to support better frequency control in the long term, and makes recommendations on how this could be achieved. For the immediate term the AEMC recommends three rule change requests to improve information/transparency around frequency control issues and existing frequency control markets. The major deliverable of this report is a work plan, developed collaboratively by the AEMC, AEMO and the AER, detailing actions to be taken by the market bodies, in consultation with stakeholders, to address these longer term issues. This report also concludes a number of Finkel Panel recommendations concerning frequency control that were directed to the AEMC.

2 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.

3 This transformation presents both opportunities and challenges for power system security and reliability. A power system is:

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

4 The current reliability standard was met for the NEM in 2016/17 consistent with previous years. Modelling and other analysis shows that the reliability standard will be met in all regions of the NEM in the near to medium term.[1] However, recent events, such as load shedding in South Australia and NSW and the announced closure of generators, have led to a greater focus on reliability. The AEMC is reviewing the market and regulatory frameworks for reliability in the NEM through its *Reliability frameworks review* to make sure that they are sufficiently flexible to facilitate and keep up with the pace of this transition, while providing energy reliably to consumers at least cost.

5 However, it is becoming harder for AEMO to manage power system security as the energy mix changes. The AEMC, through its *System security market frameworks review*, and the Finkel Panel, through its *Independent review into the future security of the NEM*, have identified the system security challenges associated with the transformation of the energy sector. These challenges are reflected in the mixed security performance of the power system in 2016/17, resulting in a less secure power system and in some cases load being

1 See: https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

shed. Undertaking work to improve security outcomes in the NEM is therefore a priority. It is critical that the system is able to respond to the changing operational dynamics of the system to maintain power system security.

6 The current system security challenges relate to two important technical parameters of the power system: system strength and frequency control. The AEMC is acting on the need to address these challenges through a range of rule changes and reviews in its system security work program. To date, the AEMC has made five rule changes, and two more are underway, to help AEMO, as the body responsible for maintaining power system security, address the immediate system security needs of the transforming system.

7 In relation to the issue of low system strength, the Commission has made rules obliging TNSPs to procure minimum required levels of system strength in response to any shortfall declared by AEMO. The Commission understands that in the absence of the full implementation of this framework, operational challenges in maintaining minimum system strength is requiring AEMO to intervene in the South Australian market on a more frequent basis. The impact of this increased intervention, and solutions to address it, will be the subject of continued collaboration between the AEMC and AEMO, as identified in the Commission's *Reliability Frameworks Review*.

8 The other important technical parameter of power system security that needs to be addressed is frequency control.[2] The frequency of the power system varies whenever the supply from generation does not precisely match customer demand. Effective control of power system frequency involves the provision of inertia,[3] the use of emergency frequency control schemes and the coordination of a range of frequency control ancillary services (FCAS). 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 (by decreasing generation or increasing load). FCAS are intended to work together to maintain a steady frequency during normal operation, and to stabilise and restore the frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

9 The ongoing transformation of the power system presents both opportunities and challenges for AEMO's ability to manage power system frequency. The AEMC commenced the *Frequency control frameworks review* in July 2017 to explore, and provide advice to the COAG Energy Council and market participants on, changes to the market and regulatory frameworks that may be required to meet the challenges in maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generating mix. The review also provided the vehicle through which the AEMC could address the Finkel recommendations assigned to the AEMC in relation to frequency control.

Key findings of this review

10 Through this review the AEMC, in consultation with stakeholders, has considered five key

2 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).

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.

issues related to frequency control. This report sets out the AEMC's analysis, conclusions and recommendations on each of these issues, as summarised below.

1. **Frequency control during normal operation.** Frequency performance under normal operating conditions has been deteriorating in recent times, primarily as a result of generators decreasing or removing their responsiveness to minor frequency deviations. Drawing on AEMO's technical advice, the AEMC has explored this deterioration and possible ways in which it could be addressed. AEMO is undertaking a range of actions in an attempt to better understand the drivers of the deterioration, and to appropriately address it. AEMO advises that there is no immediate need to implement regulatory change to address the deterioration before the results of its short term actions to understand the issue are known, and that current regulatory tools are expected to be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard within this timeframe. This report therefore does not recommend any regulatory change in the immediate term to address the deterioration, but concludes that there is a need to find a more permanent solution to the issue. This report provides a detailed explanation of one possible policy mechanism, referred to as a deviation pricing mechanism, which could be further developed to efficiently value the provision of frequency services under normal operation in the longer term, and proposes to continue to explore this mechanism (and others) so that the regulatory arrangements for frequency control evolve to keep pace with the system transformation.
2. **Future FCAS frameworks.** The AEMC has examined the broader structure of the existing FCAS markets to determine whether they will remain fit for purpose in the longer term as the power system changes, how to most appropriately incorporate fast frequency response, or enhance incentives for fast frequency response within the existing markets, and longer-term options to facilitate co-optimisation of energy, FCAS and inertia. This report sets out a spectrum of potential frameworks for the procurement and dispatch of FCAS to address the potential deficiencies of the existing arrangements as the system security needs of the system changes, and concludes that the best approach to the procurement of frequency services in the longer-term will need to be performance-based, dynamic and transparent. This report also extends the AEMC's analysis of the deviation pricing mechanism referred to above to incorporate the provision of other frequency services such as contingency FCAS, inertia and fast frequency response.
3. **Frequency monitoring and reporting, and forecasting.** The AEMC has explored ways in which the existing forecasting and frequency reporting arrangements could be adjusted to enhance the operation of the frequency control frameworks. This report proposes two rule change requests to promote transparency of the frequency performance of the power system and the competitiveness of FCAS markets. It also describes the range of initiatives underway to improve AEMO's approach to supply and demand forecasting.
4. **Participation of distributed energy resources in system security frameworks.** The AEMC has explored the potential for distributed energy resources to provide system security services. This report concludes that there are some existing inefficient

regulatory barriers that may hinder or prevent distributed energy resources from providing these services. It makes recommendations on how these barriers could be addressed, and sets out some issues that AEMO, Energy Networks Australia and other parties should bear in mind when conducting trials of distributed energy resources and making decisions in this space.

5. **AEMO's market ancillary services specification (MASS).** The MASS underlies the provision of market ancillary services (i.e. FCAS) in the NEM. It sets out the detailed specification for each of the market ancillary services and how a market participant's performance is measured and verified when providing these services. The AEMC has explored whether there are aspects of the MASS that could be amended to facilitate and better value the provision of FCAS from new technologies, including storage, aggregated distributed energy resources and demand response. AEMO has signalled an intention to commence a review of the MASS in August 2018. This report sets out some issues that AEMO should consider in its review, including whether the time specifications for the contingency services as currently set out in the MASS (i.e. 6 seconds, 60 seconds and 5 minutes) will continue to be fit for purpose as the energy system changes.

11 These conclusions and recommendations, set out in full in the table at the end of this summary, represent the completion of this stage of the review. They also represent the delivery of the Finkel Panel recommendations assigned to the AEMC for further review, within the time frames put forward in that review. These recommendations are now substantially complete, as set out in the table below.

Table 1: How the AEMC has addressed the Finkel recommendations for system security

FINKEL RECOMMENDATION	AEMC RESPONSE
Resisting frequency changes By mid-2018 the AEMC should require TNSPs to provide and maintain a sufficient level of inertia for each region or sub-region. See Finkel recommendation 2.1	The AEMC's *Managing power system frequency* rules, which commenced in July 2018, requires network businesses to maintain a minimum level of inertia that will help the system resist frequency changes.
Requiring generators to support system security By mid-2018, the AEMC should require new generators to have fast frequency response capability, and review and update the connection standards to address capabilities such as system strength. See Finkel recommendation 2.1	The AEMC's *Generating system model guidelines* rule, which commenced in September 2017, requires generators to provide more information about how their equipment performs in different scenarios to allow AEMO and network businesses to better understand and manage the power system as it changes. The AEMC has published draft rules to introduce tighter technical performance

FINKEL RECOMMENDATION	AEMC RESPONSE
	standards for generators seeking to connect to the electricity network, and a clearer process for negotiating those standards. The AEMC made a draft rule on the *Generator technical performance standards* rule change request in May 2018. Following consultation, a final rule determination is due October 2018.
By mid-2018, AEMO and the AEMC should investigate and decide on whether synchronous generators should change their governor settings to provide a more continuous control of frequency, and consider the costs and benefits of tightening the frequency operating standard. See Finkel recommendation 2.3	This *Frequency control frameworks review* has explored and consulted on a range of options to address the deterioration of frequency performance under normal operation, including a requirement that generators tighten their dead bands and a tightening of the frequency operating standard. While AEMO is undertaking a range of actions in an attempt to better understand the drivers of the deterioration and ways to address it under the existing regulatory arrangements, this report concludes that the more appropriate mechanism to procure the frequency services the system needs in the longer term is one that is incentive-based. The AEMC and AEMO will continue to work together to develop such a mechanism, in consultation with stakeholders.
Maintaining a strong system By mid-2018 the AEMC should review and update the connection standards to address capabilities such as system strength. See Finkel recommendation 2.1	The AEMC's *Managing power system fault levels* rule, which commenced in July 2018, requires network businesses to maintain system strength above agreed minimum levels at key locations in the power system, and new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system.
Facilitating fast frequency response A future move towards a market-based mechanism for procuring fast frequency response should only occur if there is a	This *Frequency control frameworks* review has considered the appropriateness of the existing FCAS market arrangements to meet emerging system needs, including the need for faster frequency services, and ways to

FINKEL RECOMMENDATION	AEMC RESPONSE
demonstrated benefit. See Finkel recommendation 2.2	facilitate co-optimisation between energy, FCAS and other system characteristics such as inertia. The AEMC and AEMO will continue to assess the need for fast frequency response and, if there is a need, the most efficient means to procure that service.
Enabling the participation of distributed energy resources The AEMC should review the framework for power system security with respect to participation by distributed energy resources, and report on proposed rule changes to better incentivise this. See Finkel recommendation 2.5	The AEMC has reviewed the regulatory framework as it relates to the participation of distributed energy resources in system security frameworks through this *Frequency control frameworks review*. The AEMC has identified some potential barriers to distributed energy resources providing system services, including FCAS, and makes recommendations, including proposed rule changes, on how they could be addressed. Further consideration of the findings of the AEMC's *Distribution market model* project were progressed through the AEMC's 2018 *Electricity network economic regulatory framework review*, which was published in July 2018.
Facilitating trials and innovative approaches By end-2018, the AEMC should review and update the regulatory framework to facilitate proof-of-concept testing. See Finkel recommendation 2.8	There is an existing mechanism by which this can occur. The AER considers each proposal on a case by case basis and can issue a letter of no action to allow proof of concept testing.

Next steps for the AEMC's frequency control work program

12 Despite the completion of the Finkel review action items, there is more work to be done. This report highlights other issues that need to be addressed, as detailed in the table below, including the most appropriate mechanism to incentivise the provision of services that help support good frequency control in the longer term.

13 The key deliverable of this stage of the review is a work plan. The work plan sets out actions to be undertaken by the AEMC, AEMO and the AER, in consultation with stakeholders, to address a range of frequency control issues over the next few years. It was developed collaboratively by the AEMC, AEMO and the AER and is set out in detail in Chapter 4 of this report. Together with the rules made by the Commission to date as part of

its system security work program, it progresses the issues identified in the *Integrated System Plan 2018* relevant to frequency control ancillary services.

14 The Commission has concluded this stage of this Review and made a number of recommendations to improve frequency control in the NEM as detailed above. In particular, this report concludes the Commission's work relevant to the Finkel Review recommendations which were made to the Commission.

15 However, the report has identified issues which still need to be addressed together with a longer term collaborative work plan. The Commission will progress its part of the work plan in the coming months. The next steps for the work program for the AEMC include:

- consulting on potential longer-term mechanisms for the procurement of a primary regulating response and other frequency services as the needs of the power system evolve
- consulting with stakeholders on how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard.

16 This work is separate to the rule change requests identified above. These, and any other rule change requests related to the recommendations will be progressed concurrently and in coordination with other parts of our security work program.

17 The AEMC will continue to work closely with AEMO and other stakeholders to identify evolving challenges and opportunities so that the security needs of the system can be achieved at least cost.

Table 2: Key recommendations made in this report

	IDENTIFIED ISSUE AND AEMC CONCLUSION	RECOMMENDATION
1	Frequency performance under normal operating conditions has been deteriorating in recent times. This has been identified by AEMO and the Finkel Panel as a key system security concern for the future. The deterioration could be addressed by, among other things, the provision of primary frequency control in the normal operating frequency band (termed a 'primary regulating response'). AEMO is undertaking a range of measures to better understand (and potentially address) the issue, and expects that its existing regulatory tools will be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard while it undertakes these actions. However, the existing regulatory arrangements will not require or adequately incentivise the provision of a primary regulating response for the long term.	**Arrangements for the provision of primary regulating services** In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation. In order to develop such a mechanism, the Commission supports AEMO's trialing of changes to generator governor settings in Tasmania and the mainland, and associated technical investigations by AEMO, which are expected to be complete by December 2018. The Commission recommends that the results of these trials and investigations be used to develop an explicit mechanism to incentivise the provision of a sufficient quantity of primary regulating services to support good frequency performance during normal operation. This will be important to securing a sufficient volume of this service in the future for the evolving power system.
2	There is currently a lack of transparency regarding the frequency performance of the power system during normal operation. There is potential to improve these arrangements so that market participants are more regularly informed about issues that affect power system security, market	**AEMO reporting on frequency performance** That the AER submit a rule change request in Q3 2018 to amend the NER to require AEMO to publish: • weekly reports on frequency outcomes with respect to the requirements of the frequency operating standard

	IDENTIFIED ISSUE AND AEMC CONCLUSION	RECOMMENDATION
	participants have access to information that helps them make investment and operational decisions that impact frequency control, and the market can understand the impact of any changes made to improve frequency performance during normal operation.	• quarterly reports providing AEMO's analysis of key trends and specific events. Proposed rule drafting to give effect to this obligation is set out in this report.
3	There is a lack of regular, readily available information to participants about the general performance of FCAS markets. There is potential to improve these arrangements so that market participants and other stakeholders: • have a sense of whether the FCAS markets are efficient and effective • have an understanding of how much it costs to meet the frequency requirements of the system • are alerted to the need for FCAS and have access to trend information that helps them make investment and operational decisions.	**AER reporting on FCAS market outcomes** That the AER submit a rule change request in Q3 2018 to amend the NER to require the AER to report quarterly on the performance of FCAS markets, specifically: • the total costs of FCAS • volumes (both enabled and utilised), prices, number of participants for each of the eight FCAS markets and the technology types of those participants • commentary on key trends • an assessment of whether the FCAS markets are effective. Proposed rule drafting to give effect to this obligation is set out in this report.
4	The NER do not accommodate the aggregation of small generating units (e.g. distributed energy resources) by Small Generation Aggregators for the purpose of providing market ancillary services.	**Aggregator regulatory frameworks** That AEMO submit a rule change request to: 1. clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units

	IDENTIFIED ISSUE AND AEMC CONCLUSION	RECOMMENDATION
	In addition, the NER and the MASS do not set out clearly that a Market Ancillary Service Provider can provide market ancillary services in relation to load under its control by aggregating small generating units behind the connection point to affect the level of that load. Amending these frameworks would likely increase competition in FCAS markets and enable the owners and aggregators of distributed energy resources to capture the value of FCAS market participation.	2. enable 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 the MASS. Proposed rule drafting to give effect to this change is set out in this report.
5	The technical requirements imposed through DNSPs' connection arrangements and Australian Standard (AS) 4777[4] do not appear to value or incentivise the provision of system security services by distributed energy resources, and some of them may actually impede it. The AEMC supports the work being undertaken by Energy Networks Australia to establish a set of nationally-consistent grid connection guidelines for distributed energy resources.	**Connection arrangements and AS4777** That Energy Networks Australia, in developing its national connection guidelines, explicitly consider: • 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 extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services or participate in other energy markets. • the circumstances in which it is appropriate to limit the size of the connection, why it might be appropriate to limit the size of the connection and how this applies to hybrid systems • the technical justification for any mandated services

4 Australian Standard (AS) 4777 applies to low voltage inverters connected to the power system, which includes inverters for grid-connected solar PV systems and battery storage systems.

	IDENTIFIED ISSUE AND AEMC CONCLUSION	RECOMMENDATION
		• the expected application of AS 4777 to different connection types and sizes The Commission encourages stakeholders to input into the development of these guidelines.
6	There is currently limited visibility of the spare capacity in distribution networks and of the quantity or intentions of the growing amount of distributed energy resources to provide services, including system services. Increasing this visibility will be crucial to unlocking the potential for distributed energy resources to provide system security services (and other services) while also enabling NSPs to meet their service obligations. AEMO has indicated an intention to conduct trials of aggregated distributed energy resources to help inform its understanding of these issues.	**Technical interactions between distributed energy resources and the network** That: 1. when AEMO conducts trials of aggregated distributed energy resources providing FCAS, including virtual power plants, it assesses 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 2. when undertaking these trials, AEMO collaborate with interested and affected stakeholders, including ARENA, the local DNSP, distributed energy resource aggregators, virtual power plant, neighbouring DNSPs and affected TNSPs. 3. 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.
7	There may be aspects of the existing MASS that are inefficiently limiting participation in FCAS markets by newer technologies and undervaluing their response capabilities. AEMO has indicated an intention to test the capability of distributed energy resources through trials to inform a review of the MASS.	**Market ancillary services specification** That AEMO: 1. undertake trials of distributed energy resources providing FCAS, including virtual power plants, 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 and incorporating the outcomes of the trials (and any other trials of new technologies providing FCAS) into a review of the MASS.

	IDENTIFIED ISSUE AND AEMC CONCLUSION	RECOMMENDATION
		2. conduct a broader review of the MASS that seeks to address any unnecessary barriers to new entrants, or any aspects of the MASS that may not appropriately value services provided by newer technologies where these services are valuable to maintaining power system frequency. This should include consideration of: a. the timing specifications for each of the different FCAS b. the overlapping interactions between the different FCAS specifications. c. any changes that may be necessary to settings within the MASS d. issues raised in the most recent review of the MASS that were considered out of scope.

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APPENDICES

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1 INTRODUCTION

This chapter outlines:

- the purpose of this review
- the purpose of this report
- the scope of this review
- work being undertaken by the AEMC and other organisations that relates to this review
- key milestones and stakeholder consultation conducted throughout the review process
- the AEMC's proposed next steps for continued consideration of the issues raised in this review, and the implementation of the recommendations set out in this report
- the structure of this report.

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 national electricity market (NEM).

These challenges and opportunities were 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.[5] The *Frequency control frameworks review* has provided a means by which the AEMC can explore these issues.

The review is a comprehensive and holistic analysis of the existing frequency control arrangements in the NEM to determine whether they remain fit for purpose as the generation mix changes.

The *Frequency control frameworks review* has also provided 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:

- moving towards a market-based mechanism for procuring fast frequency response if there is a demonstrated benefit
- 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)
- considering the costs and benefits of tightening the [normal operating frequency band in the] frequency operating standard

5 A summary of the AEMC's system security and reliability work program is provided in section 1.3.1.

- 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 FFR capability (by mid-2018). This issue is the subject of a rule change request currently under the AEMC's consideration.[6]

1.2 Purpose of this report

This report sets out a number of recommendations to the COAG Energy Council on changes required to maintain effective frequency control in the NEM as it evolves. Specifically, it sets out recommendations on five key areas considered as part of the review's scope (see section 1.3).

It also reports on how the AEMC has progressed the relevant recommendations made by the Finkel Panel to the AEMC, which were due to the COAG Energy Council in mid-2018 in accordance with the timetable that was agreed with the COAG Energy Council. The AEMC's conclusions on the relevant Finkel recommendations are set out in Table 1.1.

Table 1.1: Relevant Finkel recommendations and their delivery through this review

FINKEL RECOMMENDATION	HOW THE AEMC HAS DELIVERED ON THE RECOMMENDATION (AND SECTION OF THIS REPORT WHERE IT IS ADDRESSED)
2.2 A future move towards a market-based mechanism for procuring fast frequency response should only occur if there is a demonstrated benefit.	This report sets out the likely timing of the need for fast frequency response. It concludes that there is little economic benefit in introducing a market mechanism for fast frequency response at the current time given existing inertia levels, the minimum inertia requirements that will be put in place and the system strength constraints being applied in South Australia. But, AEMO analysis suggests that faster frequency services may be needed in future. This review has considered the appropriateness of the existing FCAS market arrangements to meet emerging system needs, including the need for faster frequency services, and ways to facilitate co-optimisation between energy, FCAS and other system characteristics such as inertia. The AEMC and AEMO will continue to assess the need for fast frequency response and, if there is a need, the most efficient means to procure that service.

6 See: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

FINKEL RECOMMENDATION	HOW THE AEMC HAS DELIVERED ON THE RECOMMENDATION (AND SECTION OF THIS REPORT WHERE IT IS ADDRESSED)
	This report also recommends that AEMO: • conduct trials to better understand the capabilities of new technologies providing FCAS • review the market ancillary services specification to address any aspects of it that unnecessarily prohibit participation by newer technologies, or that do not appropriately value their capabilities. See section 3.2, section 3.5, Appendix A and Appendix E.
2.3 (a) – By mid-2018, AEMO and the AEMC should investigate and decide on a requirement for all synchronous generators to change their governor settings to provide a more continuous control of frequency with a dead band similar to comparable international jurisdictions.	This review explored and consulted on a range of options to address the deterioration of frequency performance under normal operation, including a requirement that generators tighten their dead bands. Very few stakeholders expressed support for a mandatory approach to address the deterioration – i.e. a requirement for generators to tighten their dead bands. This report concludes that providers of a 'primary regulating service' should be remunerated for it, and therefore recommends a move toward a market or incentive-based mechanism for the procurement of this service in the longer-term. The AEMC and AEMO will work together to develop such a mechanism, in consultation with stakeholders. In the meantime, AEMO is implementing a range of short term measures, including trials, to try to understand the deterioration of frequency performance and ways to stop any further deterioration. See section 3.2 and Appendices A and B.
2.3 (b) – By mid-2018, AEMO and the AEMC should consider the costs and benefits of tightening the frequency operating standard.	This review explored and consulted on a range of options to address the deterioration of frequency performance under normal operation, including a tightening of the boundaries of the normal operating frequency band. A tightened normal operating frequency band would result in earlier activation of the contingency services, and thereby drive improved frequency performance under normal operation.

<table>
<tr><th>FINKEL RECOMMENDATION</th><th>HOW THE AEMC HAS DELIVERED ON THE RECOMMENDATION (AND SECTION OF THIS REPORT WHERE IT IS ADDRESSED)</th></tr>
<tr><td></td><td>The AEMC, with stakeholder input, concluded that this approach is not the most efficient means to address the deterioration of frequency performance under normal operation. This is because:
• it risks there being less than the full quantity of contingency FCAS to respond to a contingency event
• AEMO bears no financial risk for under or over-procurement of the service
• it represents a substantial change to the current arrangements
• it would not be a quick or easy change to implement.
The AEMC and AEMO will develop longer-term options for the procurement of primary regulating services, including the creation of a new band within the frequency operating standard (i.e. creation of a new FCAS market), or the adoption of alternative incentive mechanisms.</td></tr>
<tr><td>2.5 (a) - By mid-2018, the COAG Energy Council should direct the AEMC to review the regulatory framework for power system security in respect of distributed energy resources participation.</td><td rowspan="2">The AEMC has reviewed the regulatory framework as it relates to the participation of distributed energy resources in system security frameworks through this review. The AEMC has identified some potential barriers to distributed energy resources providing system services, including FCAS. To address these barriers, this report recommends that:
• AEMO submit a rule change request to enable Small Generation Aggregators to participate in FCAS markets and clarify that Market Ancillary Service Providers can do so with small generating units
• Energy Networks Australia's development of national distributed energy resource connection guidelines explicitly consider the impact that the proposed technical requirements may have on distributed energy resources' ability to provide system services and participate in the energy markets</td></tr>
<tr><td>2.5 (b) - By mid-2019, the AEMC should report to the COAG Energy Council on proposed draft rule changes to better incentivise and orchestrate distributed energy resource participation to provide services such as frequency and voltage control.</td></tr>
</table>

FINKEL RECOMMENDATION	HOW THE AEMC HAS DELIVERED ON THE RECOMMENDATION (AND SECTION OF THIS REPORT WHERE IT IS ADDRESSED)
	• AEMO conduct trials of distributed energy resources providing FCAS to better understand their capability to do so, and to determine whether the existing technical and regulatory requirements that currently underpin the provision of these appropriately enable and value participation by distributed energy resources. See section 3.4, section 3.5, Appendix D and Appendix E.
2.1 (b) – By mid-2018 the AEMC should require new generators to have fast frequency response capability.	This is being considered in the *Generator technical performance standards* rule change request.[7] A draft determination on this rule change request was published on 31 May 2018. The draft rule does not include an explicit requirement for new generators to have the capability to deliver a specific fast frequency response – that is, it does not require all generators to have the capability to provide an active power response within a specified timeframe after frequency has moved outside of a dead band. This is because the AEMC is of the view that specific parameters of any frequency service provided by each generator, such as the speed of response, should be determined on the basis of agreement between AEMO and generators who are providing FCAS, on the basis of an assessment of the needs of the system, the cost to the generator of providing the response, and the technical limits of the generating unit. This is because different types of generators will have different technical limits as to the speed of possible frequency response, so requiring all generators to have the capability to provide a frequency response within a specific timeframe may not be physically possible, or prohibitively expensive to deliver. However, the draft rule does include a requirement for generators to have a frequency response capability that occurs without delay if frequency moves outside a dead band around 50 Hz. This

7 See: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

FINKEL RECOMMENDATION	HOW THE AEMC HAS DELIVERED ON THE RECOMMENDATION (AND SECTION OF THIS REPORT WHERE IT IS ADDRESSED)
	effectively requires those generators that are FCAS providers to provide a response as fast as is physically possible, when they are enabled to do so.

1.3 Scope of review

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

1. 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
2. reviewing the structure of FCAS markets to consider:
    a. any drivers for changes to the current arrangements, how to most appropriately incorporate fast frequency response (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 energy, FCAS and inertia provision
3. assessing whether existing frequency control arrangements will remain fit for purpose in light of likely increased need for ramping, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day
4. 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*.[8] Item 4 is based on a recommendation made by the AEMC in the final report of the *Distribution market model* project.[9]

Stakeholders largely supported the proposed scope of the review in their submissions to the issues paper, which was published in November 2017.[10]

Based on stakeholder input and its own analysis, the AEMC divided its assessment of the issues identified in the terms of reference into five key issues. These five issues form the substance of this report.

8 See: https://www.aemc.gov.au/markets-reviews-advice/system-security-market-frameworks-review

9 See: https://www.aemc.gov.au/markets-reviews-advice/distribution-market-model

10 Some stakeholders suggested additional issues that the AEMC should consider. The AEMC's response to these scope issues are set out in Appendix A of the draft report.

1. **Frequency control during normal operation.** Drawing on AEMO's technical advice, the AEMC has explored the recent deterioration of frequency performance under normal operating conditions and possible ways in which this could be addressed.
2. **Future FCAS frameworks.** The AEMC has examined the broader structure of the existing FCAS markets to determine whether they will remain fit for purpose in the longer term as the power system changes, how to most appropriately incorporate FFR services, or enhance incentives for FFR services within the existing markets, and longer-term options to facilitate co-optimisation of energy, FCAS and inertia.
3. **Frequency monitoring and reporting, and forecasting.** The AEMC has explored ways in which the existing forecasting and frequency reporting arrangements could be amended to enhance the operation of the existing frequency control frameworks.
4. **Participation of distributed energy resources in system security frameworks.** The AEMC has explored the potential for distributed energy resources to provide system services and whether there are any unnecessary regulatory barriers that prevent distributed energy resources from providing FCAS or other system services.
5. **AEMO's market ancillary services specification (MASS).** The AEMC has explored whether there are aspects of the MASS that could be amended to facilitate and better value the provision of FCAS from new technologies, including storage, aggregated distributed energy resources and demand response.

The AEMC's analysis and conclusions on each of these issues are set out at a high level in Chapter 3, and in detail in the relevant appendices of this report.

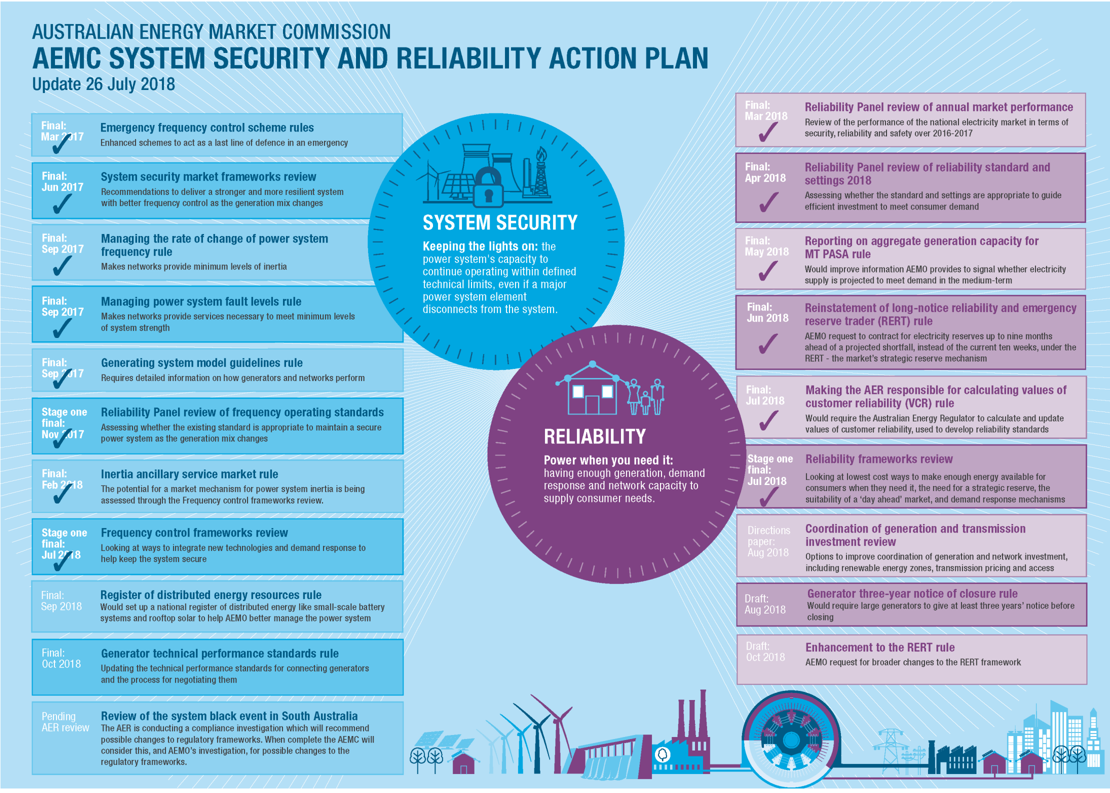
1.4 Related work

This review follows, and was 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 described below and referred to where relevant throughout this report.

1.4.1 AEMC's system security and reliability action plan

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. The action plan is set out in Figure 1.1 below.

Figure 1.1: AEMC system security and reliability action plan



Key projects in the action plan are set out below.

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.[11] 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. A summary of progress against these recommendations is set out in Figure 1.2 below.

11 See: https://www.aemc.gov.au/markets-reviews-advice/system-security-market-frameworks-review

Figure 1.2: Progress against recommendations made in the *System security market frameworks review*

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.	Draft determination on *Generator technical performance standards* rule change published 31 May 2018.
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.	Considered through the *Frequency control frameworks review.* Stage one final report published 26 July 2018.
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.	Draft determination on *Generator technical performance standards* rule change published 31 May 2018.
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.	AEMC, in collaboration with AEMO, continues to scope what is needed to meet the technical and operational needs of the system.

Managing the rate of change of power system frequency rule change

In September 2017 the AEMC made a rule on the *Managing the rate of change of power system frequency* rule change request.[12] The final rule, which commenced on 1 July 2018, places an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet those minimum levels. The AEMC concluded that the final rule would provide confidence that required levels of inertia can be maintained while minimising costs to consumers.

Inertia ancillary service market rule change

In February 2018 the AEMC made a final determination to not introduce a market mechanism for inertia, as was proposed in the *Inertia ancillary service market* rule change request.[13] Given the given the current power system operating conditions, the need to understand the practical outcomes of the new requirements of the *Managing the rate of power system frequency* rule and to assess outcomes of various programs of work, the AEMC was not satisfied that the introduction of a market mechanism for additional inertia for market benefit would meet the NEO at the time. Instead, the AEMC committed to continue to assess the potential for an inertia market mechanism through the *Frequency control frameworks review*.

Managing power system fault levels rule change

In September 2017 the AEMC made a rule on the *Managing power system fault levels* rule change request.[14] The final rule, which commenced on 1 July 2018, places an obligation on TNSPs to maintain minimum levels of system strength. The framework provides for a holistic, flexible and technologically neutral solution to issues arising from reduced system strength by requiring TNSPs to maintain system strength at the levels determined by AEMO, under a range of operating conditions specified by AEMO. The final rule also places an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system.

Review of the frequency operating standard

In March 2017 the AEMC provided terms of reference to the Reliability Panel to conduct a review of the frequency operating standards[15] that apply to Tasmania and to the mainland NEM.[16] 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:

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12 See: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

13 See: https://www.aemc.gov.au/rule-changes/inertia-ancillary-service-market

14 See: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

15 The frequency requirements that AEMO must meet are set out in the frequency operating standard. The frequency operating standard is explained in Chapter 2. For an explanation of the role and responsibilities of the Reliability Panel, see: http://www.aemc.gov.au/About-Us/Panels-committees/Reliability-panel

16 See: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard

1. Stage one addressed technical issues and changes arising from the *Emergency frequency control schemes rule change*, which commenced on 6 April 2017.[17] 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 will include a review of the settings of the frequency operating standard, including examining the boundaries of the various frequency bands and the timeframes for restoration of power system frequency following specific events. Stage two of the review was on hold while the Commission progressed the *Frequency control frameworks review*, and will recommence following the publication of this final report.[18]

Annual market performance review

The Reliability Panel's annual market performance review provides observations and commentary on the security, reliability and safety of the NEM. Among other things, it may assist governments, policy makers and market institutions to monitor the performance of the power system, and to identify the likely need for improvements to the various measures available for delivering security, reliability and safety. The latest review was published in March 2018.[19]

Reliability frameworks review

Over the past 18 months, a number of events have led to a greater focus on reliability in the NEM. The AEMC commenced the *Reliability frameworks review* to assess whether the current market and regulatory frameworks for reliability are still appropriate in light of the changing generation mix and greater opportunities for demand-side participation.

A final report on the review was published on 26 July 2018.

1.4.2 External projects

AEMO

This review was coordinated with AEMO's ongoing technical work on frequency control issues under the terms of the collaboration agreement between AEMO and the AEMC. This includes the work by AEMO on understanding the potential opportunities and challenges in operating a stable and secure power system with less synchronous generation.[20]

Below are some of the projects that are of particular relevance to the *Frequency control frameworks review.*

17 See: https://www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen

18 The Commission has issued revised terms of reference for the Panel to complete the Review of the frequency operating standard by the end of March 2019. See: [INSERT LINK]

19 See: https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

20 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability

- **Ongoing technical investigations.** AEMO is undertaking ongoing investigations of some of the more immediate issues associated with declining frequency performance in the NEM. This work is set out in more detail in section 3.1 and in Appendix A.
- **Review of the causer pays procedure.** AEMO is conducting a review of the procedure that it uses as the basis for recovering costs associated with procuring regulating FCAS, known as the 'causer pays procedure'.[21] The *Frequency control frameworks review* considered potential improvements to the settings and assumptions used in the causer pays procedure, which are set out in Appendices A and B.
- **The *Integrated system plan*.** On 17 July 2018 AEMO published its *Integrated system plan*, which is described as "a cost-based engineering optimisation plan that forecasts the overall system requirements for the NEM" over a 20-year period to inform the transmission developments that will be needed to reliably and securely supply customers at least cost.[22] The plan takes into account the physical requirements of the future power system, including frequency. It notes that the transformation of the energy system will require the adoption of new technologies and approaches to provide the services needed to operate the power system that are currently provided predominantly by thermal generation, including frequency. The plan concludes that wind, solar, battery, pumped hydro, and demand-based resources are likely to compete for the provision of a projected increasing need for FCAS.
- **The *Power system requirements* reference paper.** In March 2018 AEMO published a paper explaining the technical and operational needs of the power system.[23] The paper, among other things, sets out the "fundamental technical attributes" of the power system, including frequency management, and AEMO's views on the essential services needed to maintain those attributes.

Energy Networks Australia / CSIRO

In 2017 Energy Networks Australia and the CSIRO published an *Electricity network transformation roadmap* to "provide detailed milestones and actions to guide an efficient and timely transformation over the 2017-27 decade."[24] 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*. Specifically, the roadmap notes that:
  - effective market-based approaches can be developed to provide assurance of capacity, balancing and ancillary services important to system security
  - there will likely be a need to amend the existing service definitions in the NEM to ensure previously inherent services, such as inertia and fast frequency response, are explicitly identified and secured.
- *Power system forecasting*. The roadmap notes that:

21 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Co nsultation
22 [INSERT LINK WHEN PUBLISHED]
23 See: https://www.aemo.com.au/Media-Centre/AEMO-publishes-Power-System-Requirements-paper
24 See: http://www.energynetworks.com.au/electricity-network-transformation-roadmap

- a range of new operational models and techniques to enhance reliable forecasting of variable renewable generation and distributed energy resources will be needed to better predict where environmental and system constraints could lead to system security issues
- new methods for providing this information to the market operator for incorporation into system control functionality will be required.

These findings and recommendations are consistent with those presented in this review.

1.5 Stakeholder consultation

1.5.1 Public consultation

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

- provided 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.

The AEMC received 19 written submissions on the issues paper.

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 AEMC published a draft report on the review on 20 March 2018. The draft report:

- provided an overview of frequency control in the NEM
- described the drivers of change that give us cause to look at the frequency control arrangements in the NEM
- set out the AEMC's approach to thinking through any changes to the existing frequency control arrangements
- set out draft recommendations on ways in which the market and regulatory frameworks for frequency control could be improved to address identified issues, both in the short and long term.

The AEMC received 25 written submissions on the draft report.

All papers and stakeholder submissions are available on the AEMC website.[25]

25 See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

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) was established to provide high-level input and strategic advice to the AEMC throughout the course of the review.

The AEMC 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 Next steps for this review

The Commission has concluded this stage of this Review and made a number of recommendations to improve frequency control in the NEM. However, the report has identified issues which still need to be addressed, together with a longer term collaborative work plan, which will provide a vehicle for:

1. the AEMC, AEMO and the AER to implement the various actions in the work plan set out in Chapter 4, and report on progress against those actions
2. the AEMC to consult on potential longer-term mechanisms for the procurement of a primary regulating response and other frequency services as the needs of the power system evolve (as is proposed in the work plan)
3. the AEMC to consider, and consult with stakeholders on, how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard. This includes consideration of whether the NER or the frequency operating standard should:
    a. prescribe in more detail the required frequency performance within the normal operating frequency band
    b. include a system standard in relation to the rate of change of power system frequency.

The Commission intends to progress these issues in the coming months.

The AEMC will continue to work closely with AEMO and other stakeholders to identify emerging challenges and opportunities so that the security needs of the system can be achieved at least cost.

The AEMC will continue the technical working group that was established for this review. The working group will provide a valuable means for the AEMC to gain input and feedback on the three items above.

1.7 Structure of this report

The remainder of this report is structured as follows:

- Chapter 2 summarises the existing regulatory arrangements for frequency control in the NEM and sets out the context for the AEMC's consideration of frequency control issues through this review.
- Chapter 3 provides an overview of the AEMC's analysis and conclusions on the five issues identified through this review.
  - Section 3.1 - Frequency control during normal operation.
  - Section 3.2 - Future FCAS frameworks.
  - Section 3.3 - Frequency monitoring and reporting, and forecasting.
  - Section 3.4 - Participation of distributed energy resources in system security frameworks.
  - Section 3.5 - AEMO's market ancillary services specification (MASS).
- Chapter 4 describes the work plan that the AEMC, AEMO and the AER have jointly developed to address the issues identified through this review over the short to longer term.

The appendices to this report provide further detail on the five key issues considered through this review, including a detailed description, summary of stakeholder views, and the AEMC's analysis and conclusions for each issue..

- Appendix A provides further detail on the degradation of frequency performance during normal operation and the development of an explicit mechanism to incentivise primary regulating services along with other potential future changes to the FCAS frameworks.
- Appendix B focuses on the policy options set out in the draft report in relation to improving frequency performance during normal operation.
- Appendix C covers frequency monitoring and reporting, and forecasting of supply and demand in the NEM.
- Appendix D discusses issues related to the participation of distributed energy resources in the system security frameworks.
- Appendix E discusses potential changes to AEMO's MASS to remove barriers for the provision of FCAS by distributed energy resources and other new technologies.

2 CONTEXT

This chapter provides an overview of:

- how the existing regulatory framework is set up to enable frequency control in the NEM
- the drivers of change that gave the AEMC cause to review these arrangements
- the AEMC's approach to assessing the issues identified for consideration through this review.

2.1 Overview of frequency control

2.1.1 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.[26]

AEMO is required under the National Electricity Rules (NER) to operate and maintain the power system in a "secure operating state". 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 (such as the failure of a single transmission element or generator) or a protected event, in accordance with the power system security standards.

Frequency control is a key element of power system security. 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). To maintain a stable system frequency close to the nominal system frequency, AEMO must balance the supply of electricity into the power system against consumption of electricity at all times. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.[27]

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

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

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

27 A more detailed explanation of power system frequency and frequency variation is provided in Appendix C of the draft report.

- **The frequency operating standard.** The frequency operating standard defines the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. 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.
- **Frequency control ancillary services (FCAS).** FCAS are procured by AEMO to increase or decrease active power over a timeframe that meets the requirements of the frequency operating standard. There are two types of FCAS: regulating and contingency. Regulating FCAS is used to correct small deviations away from 50 Hz, while contingency FCAS are used to respond to larger frequency deviations, for example as a result of a contingency event. In the NEM, FCAS is sourced from eight markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.
- **Generator technical performance standards.** The levels of performance for equipment connecting to the power system are set out in performance standards for each connection. These performance standards help AEMO maintain the power system in a secure and safe operating state and manage the risk of major supply disruptions. The standards in the NER cover a range of technical capabilities for connecting generators, including frequency control and response to frequency disturbances during and following contingency events.
- **Emergency frequency control schemes.** Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. 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. The Commission's *Emergency frequency control schemes* rule (which commenced on 6 April 2017) established a framework for the consideration and management of power system frequency risks arising from non-credible contingency events. The rule places an obligation on AEMO to undertake, in collaboration with transmission network service providers, a power system frequency risk review (PSFRR) at least every two years of risks associated with non-credible contingency events.[28] The purpose of the PSFRR is to assess:
  - whether there is a need to introduce, modify or adapt emergency frequency control schemes to shed load or generation in a way that limits the consequences of some non-credible contingency events, and/or

28 AEMO recently published the final report of the PSFRR 2018, which recommends material changes to emergency frequency control schemes for both SA and Queensland. It also recommends the declaration of a protected event for SA designed to manage risks relating to a potential black system caused by transmission line failure and subsequent islanding during destructive wind conditions in SA.

- whether it would be economic for AEMO to operate the power system in a way that limits the impacts of certain high consequence non-credible contingency events through the declaration of a “protected event”.

A more detailed explanation of each of these components of the regulatory framework is set out in Chapter 2 of the draft report.

2.1.2 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 to stabilise and restore the power system frequency.

Conventional electricity generators, like hydro, coal and gas, operate with large spinning turbines that are synchronised to the frequency of the power system. The large rotating mass of the turbine and alternator of a synchronous generating unit 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 determines the amount of time that is available to arrest the change in frequency before it moves outside of the permitted bands of the frequency operating standard. The rate of change of frequency is proportional to the 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 – this is a role for frequency control services.

The terms ‘primary’ and ‘secondary’ are used to describe two types of frequency control services used in the NEM.

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.

Primary frequency response can be provided by:

- the variation of generator output by 'governor systems' that regulate the output of generating units[29]
- the variation of active power supplied to or consumed from the power system by inverter-based generation and loads.

In the NEM, primary frequency control services that operate outside the normal operating frequency band of the frequency operating standard are procured through the fast and slow contingency FCAS markets. Primary frequency control 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.

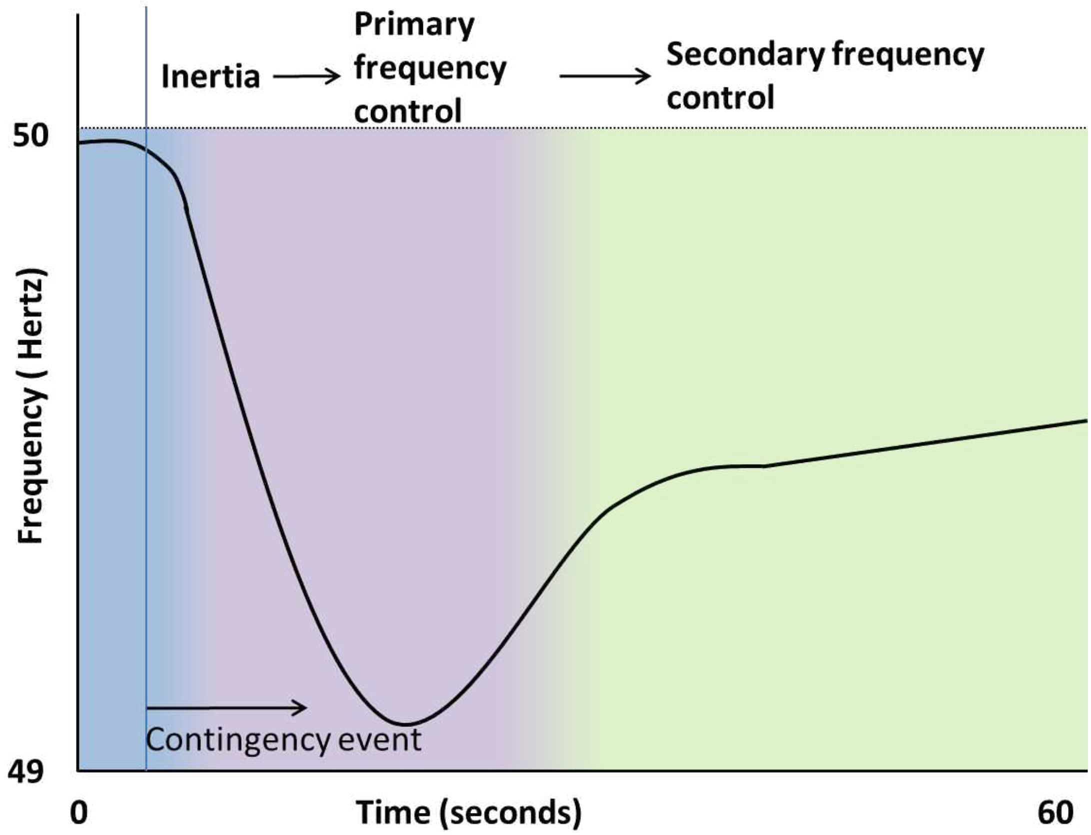
Secondary frequency control services are those that are intended to restore power system frequency to the normal operating frequency band. Under the current market and regulatory arrangements in the NEM, secondary frequency control is provided by:

- generators and loads that are enabled to provide regulating FCAS – these providers vary their generation or load in response to signals sent via AEMO's automatic generation control (AGC) system
- the delayed contingency service - these providers vary their generation or load in response to a local measurement of frequency or signals sent via the AGC system.

Effective frequency control requires the coordination of inertia and primary and secondary frequency control services, as shown in Figure 2.1 below.

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

Figure 2.1: Interaction between inertia, and primary and secondary frequency control



As the figure 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 normal operating frequency band. Rather, this is achieved through the provision of secondary frequency control services.[30]

Beyond the time frames of primary and secondary frequency control, generation capacity is dispatched via the NEM dispatch engine to maintain a balance between supply and demand.

In addition to these services, AEMO is of the view that a 'grid forming service' is needed to set the frequency to which the rest of the system is able to be synchronised. It describes grid forming as the ability of the power system to set and maintain power system characteristics such as voltage and frequency. AEMO notes that "in large, synchronous

30 A more detailed description of the characteristics of primary and secondary frequency control is included in the AEMO advice for this review. See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

power systems like the NEM, frequency has historically been set by synchronous generating units as a by-product of their normal operation"[31] and that as synchronous generators retire, the pool of system restart ancillary service providers will shrink without the introduction of new plant capable of proving grid forming services. AEMO notes that new system restart ancillary services can be provided by pumped hydro synchronous generators which have already demonstrated grid forming capability, but could also be provided by non-synchronous plant, including wind, solar, and batteries, fitted with grid forming inverters.[32] In their submissions to the issues paper, Tesla and S&C Electric Company 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.[33]

2.1.3 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:

- during normal operating conditions
- during credible contingency events
- during significant non-credible contingency events.

Each of these is described in more detail below.

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
- 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.

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

32 See: AEMO, Integrated system plan, July 2018, pp. 74-75.

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

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.

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.[34] Such contingency events are known as credible contingency events.[35]

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.

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.

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 aim to maintain the frequency within the extreme frequency excursion tolerance limit.[36]

34 See clause 4.2.4 (a) of the NER.

35 See clause 4.2.3 (b) of NER.

36 Emergency frequency control schemes are described in detail in section 2.1.4 of the draft report.

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 Appendix A.

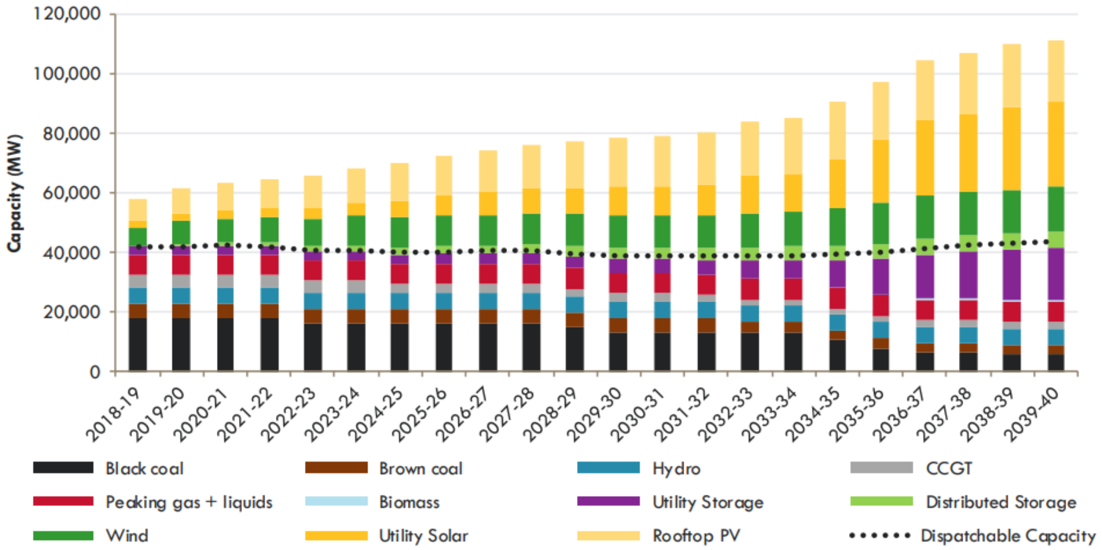
2.2 Drivers of change

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 2.2 shows AEMO's projections of NEM generation capacity over the next 20 years.[37] These projections show a decline in the amount of coal generation capacity, and an increase in the amount of wind and solar capacity.

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

Figure 2.2: **Forecast NEM generation capacity**



Source: AEMO, *Integrated system plan*, June 2018, p. 21.
Note: The graph shows AEMO's projections of the NEM generation mix transformation, modelled under neutral scenario assumptions.

This transformation has potential implications for the management of power system frequency. Some renewable energy generation technologies are by nature variable – solar PV systems generate electricity when the sun shines, and wind farms 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:

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

These drivers are creating challenges for conventional forms of frequency control in the NEM and making it more challenging for AEMO to manage power system security. 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, and the providers of those services, 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 to support good frequency control and enable the participation of emerging technologies. This review sets out the AEMC's analysis and conclusions in response to this question. 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.

The remainder of this chapter summarises the two drivers of change set out above.

2.2.1 Changing frequency control capability

Exit of traditional providers of inertia

As explained in section 2.1.2, inertia is naturally provided by conventional electricity generation technologies (such as hydro, coal-fired and gas-fired generators) that operate with large spinning turbines and alternators that are synchronised to the frequency of the grid. As most generation in the NEM has historically been synchronous, the inertia they provide has not been separately valued. The gradual withdrawal of synchronous generation is contributing to a reduction in the availability of inertia, making it increasingly challenging for AEMO to maintain the power system in a secure operating state.

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.[38]

Declining levels of inertia was the subject of the *Managing the rate of change of power system frequency* and *Inertia ancillary service market* rule change requests that the AEMC considered in 2017. Through the first rule change request, the AEMC concluded that a secure power system demands the availability of minimum levels of inertia at all times, and as such made a rule requiring TNSPs to procure minimum required levels of inertia or alternative frequency control services, in the event that AEMO declares there to be a shortfall in any of the NEM regions. On 29 June 2018, AEMO published its inertia requirement methodologies and minimum inertia levels for the NEM.[39] AEMO has declared that there are no inertia shortfalls in the NEM at this time.

Exit of traditional providers of FCAS, and entry of new providers

The regulating and contingency FCAS markets have historically attracted participation by synchronous generation. The withdrawal of synchronous generation therefore also contributes to a reduction in the availability of these services in the NEM. If this synchronous generation is displaced (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources, and there is growing evidence that this is starting to occur.

On 1 July 2017 the provision of ancillary services was unbundled from the provision of energy as a result of a rule change made by the AEMC in 2016.[40] The unbundling framework

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

39 AEMO, Inertia requirements and inertia shortfalls, 29 June 2018.

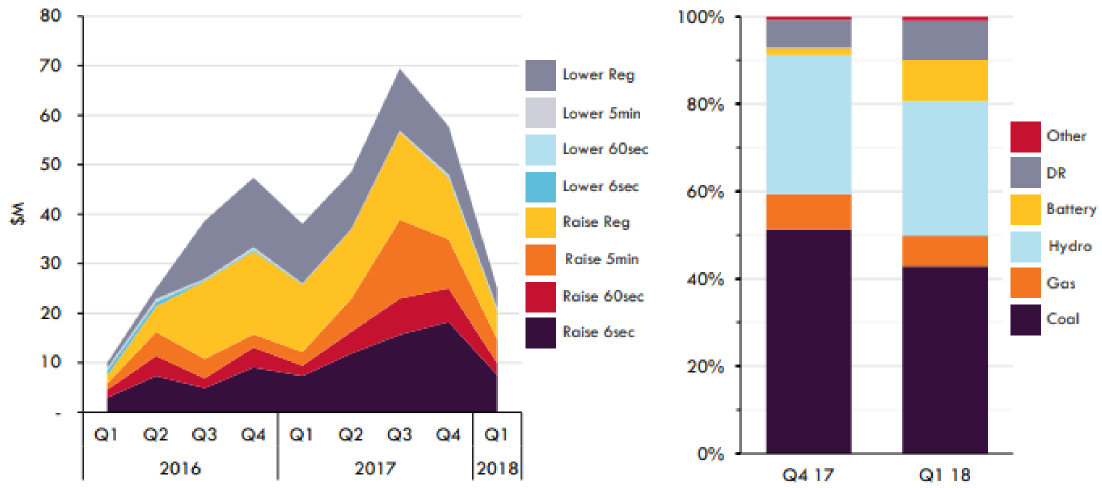
40 See: https://www.aemc.gov.au/rule-changes/demand-response-mechanism

established a new type of market participant – a Market Ancillary Service Provider – who can offer appropriately classified ancillary services loads or aggregation of loads into 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, to enhance competition in these markets and better enable AEMO to manage the frequency of the power system. EnerNOC, a provider of energy intelligence software and demand response services, registered as a Market Ancillary Service Provider in 2017 and is now participating in the raise FCAS markets by offering a reduction in its aggregated portfolio of mostly commercial and industrial loads. EnerNOC reports that it is providing up to 70 MW of FCAS to support system security, making it the first time that distributed demand-side resource have provided grid balancing ancillary services in the NEM.[41]

At about the same time, the Hornsdale Power Reserve was commissioned and began participating in the energy and FCAS markets.

AEMO reports that during Q1 2018 these two new technologies (i.e. demand response and battery storage) captured a larger share of FCAS markets. They supplied about 20 per cent of raise FCAS, compared to 8 per cent in Q4 2017, displacing higher priced supply from existing technologies (largely coal, as shown in the right side of Figure 2.3). AEMO notes that this increased competition in the FCAS markets coincided with a reduction in the price of offers from some existing providers, as shown in the left side of Figure 2.3.

Figure 2.3: Quarterly FCAS cost by service, and raise FCAS supply by fuel type



Source: AEMO, *Quarterly Energy Dynamics - Q1 2018*, p. 13.

This evidence suggests not only that these newer technology types are capable of providing FCAS, but they are increasing competition in those markets. The AEMC only expects this

41 See: https://www.enernoc.com/press-releases/20156

trend to continue as more participants seek to participate in the FCAS markets using newer technologies. For example, a recent trial at the Hornsdale indicate that wind farms are technically capable of delivering FCAS.[42] ARENA has provided funding to investigate this capability further at the Musselroe wind farm in Tasmania.[43]

Emerging need for more, and faster, frequency control

The increasing variability of supply and demand as a result of the connection of non-dispatchable capacity is likely to increase the need for the provision of frequency control services from the market.

As the variability of supply and demand increases and the amount of inertia decreases, the amount and speed of FCAS response needed to keep system frequency within the requirements of the frequency operating standard (and avoid load or generator shedding) increases.

As explained above, there are a range of new technologies connecting to the system that are capable of providing FCAS. Some of these technologies offer the potential to provide frequency response services that act much faster than the existing services, perhaps as quickly as a few hundred milliseconds. 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 detail in Appendix A.

Reduction in frequency response during normal operation

Generator frequency response

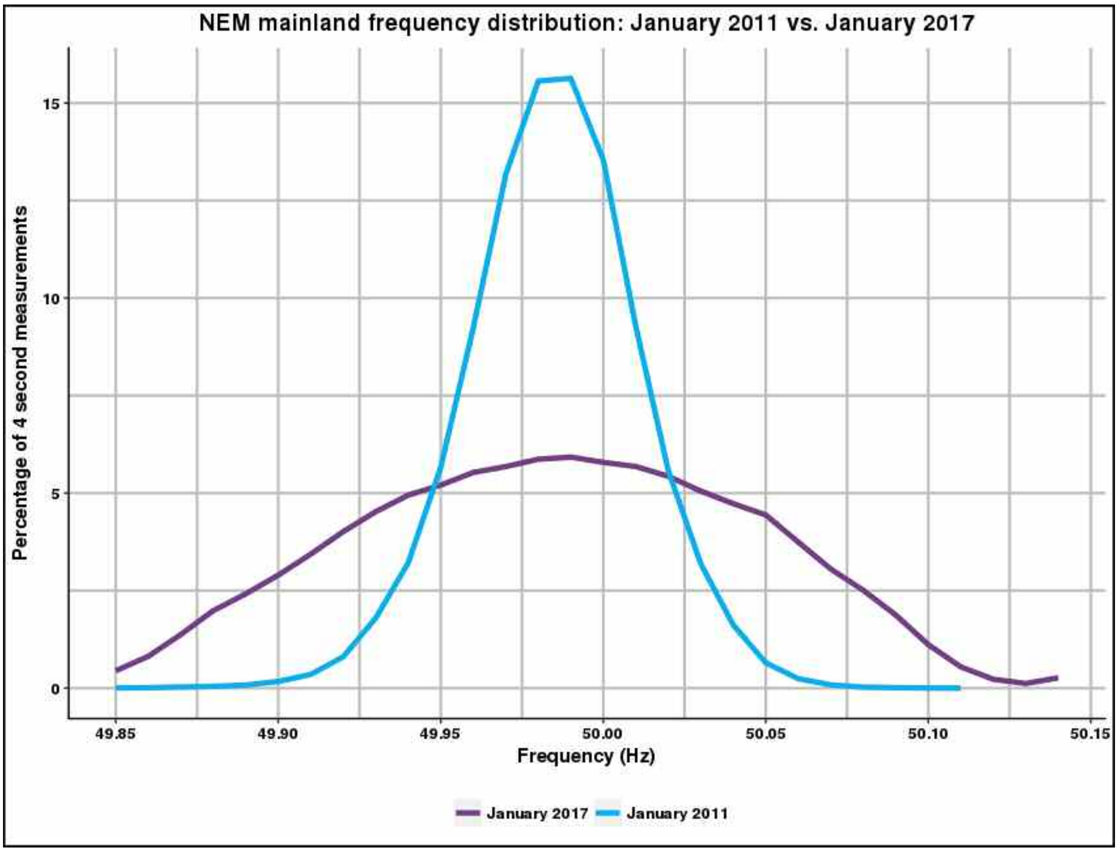
Frequency performance under normal operating conditions has been deteriorating in recent times. That is, there has been a flattening of the distribution of frequency within the normal operating frequency band, as shown in Figure 2.4. As a result, the mainland and Tasmania power systems increasingly operate at frequencies further away from 50 Hz than has historically been the case. AEMO has reported an increased incidence of exceedance events, where the power system frequency falls outside the normal operating frequency band.[44]

42 See: https://www.aemo.com.au/Media-Centre/AEMO-and-ARENA-looking-to-evolve-traditional-electricity-market

43 See: https://arena.gov.au/assets/2018/03/ARENA-Media-Release_Musselroe-Woolnorth-FCAS-wind-farm-trial-07032018.pdf

44 AEMO, Frequency monitoring – three year historical trends, 9 August 2017, p.7.

Figure 2.4: Frequency distribution profile NEM mainland: Jan 2011 – Jan 2017



Source: AEMC analysis of 4 second frequency data provided by AEMO.

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 band. Some of the consequences of deteriorating frequency 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 performance, causes of the deterioration and the AEMC's analysis and conclusions on the issue are set out at a high level in Chapter 3 and in detail in Appendix A.

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 response.[45] Analysis undertaken by consultants, DIgSILENT, for AEMO identified a reduction in load frequency response as a contributing factor to the decline of frequency performance in the NEM under normal operating conditions.[46] DIgSILENT's investigations indicated that the impact of this change may be slight at present but is expected to grow over time as older, direct-connected equipment is replaced with newer, inverter-connected equipment.[47]

2.2.2 Increased variability and unpredictability of supply and demand

As set out above, some renewable energy generation technologies are by nature variable. 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.

The predictability of changes in power output has also been affected by technological developments, market and regulatory developments and innovation by demand-side management providers. 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. However, these developments have implications for power system security.

The concept of predictability is important because it affects 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.

Large-scale generation and load

Large-scale generators in the NEM must be classified as either scheduled, semi-scheduled, or non-scheduled generators.[48] 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.[49]

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45 Inverter-connected loads are connected to the power system through power electronic equipment that separates the electrical frequency of the device from 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.

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

47 Ibid.

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

49 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.

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.

With changes in output from semi-scheduled and non-scheduled generators, and 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 affects ramping requirements because there is a need to:

- meet rapid aggregate changes in output from non-dispatchable capacity as the sun rises and sets
- respond to sudden changes in output from non-dispatchable sources of supply within the dispatch interval due to changing weather conditions
- respond to sudden changes in the operational behaviour of price responsive flexible demand; including batteries, home energy management systems and large non-scheduled load.

The AEMC considered the first issue through the *Reliability frameworks review*. Specifically, it explored 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 final report on the review was published on 26 July 2018.[50]

The second issue is the more relevant for this review, and is described in detail in section 3.2.1 of the draft report. Forecasting the levels of scheduled generation to dispatch may become more difficult with higher proportions of non-dispatchable capacity and flexible demand in the market. This could potentially increase the overall levels of uncertainty in the five-minute dispatch process, which may influence the need for services to meet the requirements of the frequency operating standard. These more rapid changes can influence the need for capacity that is able to respond quickly to manage frequency through FCAS or other frequency control frameworks.

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 (i.e. those set out in section 2.1) are expected to address the mismatch. However, as explained in Chapter 3 and Appendix A, there may be ways in which these arrangements could be improved.

Distributed energy resources

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

AEMO's load (or demand) forecasting has typically relied on the underlying diversity in consumer behaviour. Generally, not all consumers use electricity at the same time or in the same ways, which means that demand forecasting has historically been relatively predictable. However, the increased uptake of distributed energy resources[51] is presenting challenges for AEMO in managing power system security.

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. But it is expected to grow.

The operation of distributed energy resources in aggregate may be less predictable for AEMO and network service providers, particularly if they are driven by proprietary algorithms. 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. Virtual power plants (comprising many distributed energy resources) that fall below AEMO's threshold for scheduled or semi-scheduled generators are not centrally dispatched by AEMO. As a result, AEMO has limited visibility and no direct levers to control the operation of distributed energy resources to maintain power system security in real time.

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 the frequency control frameworks will need to adapt to support good frequency performance into the future.

Potential improvements to AEMO's forecasting arrangements to address some of these issues are discussed in Appendix C.

A range of other initiatives are underway to help AEMO better understand where distributed energy resources are and how they operate, including:

- AEMO's demand-side participation guidelines.[52] These guidelines require registered participants to submit information about demand-side participation to AEMO so that AEMO can take it into account when developing and using load forecasts.
- *Register of distributed energy resources* rule change request. The AEMC is considering a rule change request from the COAG Energy Council that seeks to establish a national register of distributed energy resources to give AEMO and network businesses more data to help keep the power system safe and secure.[53] On 26 June 2018, the AEMC published a draft rule to establish a register of distributed energy resources. The register would give AEMO and NSPs visibility of where distributed energy resources are connected so they can plan and operate the power system more efficiently.

51 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

52 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

53 See: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources

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, were not within the scope of this review and are therefore not discussed further in this report. The Commission is working with AEMO to develop a joint work program on distributed energy resources with the objective of better coordinating the various areas of work that the Commission and AEMO are currently undertaking on a range of distributed energy resources-related issues. One aspect of this work program is a collaboration between AEMO, the AEMC and the AER to establish a NEM virtual power plant trial program. The trials will be used to support an understanding of the technical and regulatory requirements associated with virtual power plants providing energy, FCAS and network support services. The intention is that the trials will inform any future amendments to the regulatory framework to enable the power system and consumer benefits virtual power plants can offer.

2.3 Assessment framework

The overarching objective guiding the Commission's approach to this review is the national electricity objective (NEO). The definition of the NEO, and the AEMC's view on the relevant aspects of the NEO for this review, are set out in section 4.1 of the draft report.

2.3.1 Trade-offs inherent in frequency control frameworks

The key question for this review was how to create frequency control frameworks that minimise the costs of meeting the requirements of the frequency operating standard in light of the drivers of change set out in the previous section.

Broadly, the options to deliver this objective can be thought of as reflecting greater or lesser reliance on two principal approaches:

- 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.

There are different costs and benefits for both approaches. Intervention-based approaches tend to provide a high degree of certainty that a secure supply of electricity will be achieved. 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.

However, the Commission is of the view that, in most instances, intervention-based approaches are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. This is because markets enable 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). Intervention-based approaches can limit the potential benefits of a well-functioning market, and thereby impose costs and risks on consumers. By allocating risks to market participants, markets provide financial incentives to make efficient decisions and provide incentives for innovation, to the benefit of consumers.

The AEMC developed the following approach to assessing potential changes to the market and regulatory frameworks for frequency control in light of the trade-offs set out above:

1. Define the issues.
2. Determine the options available.
3. Assess the range of options against the NEO and the following guiding principles:
   a. 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.
   b. Efficient investment in, and operation of, energy resources to promote a secure supply. Any frequency control framework should aim to deliver efficient investment in, and operation of, energy resources to promote a secure supply of electricity for consumers.
   c. Technology neutrality. Regulatory arrangements should be designed to take into account the full range of potential market and network solutions, not particular technologies.
   d. Flexibility. Regulatory arrangements must be able to remain effective in achieving security outcomes over the long-term in a changing market environment.
   e. Transparency, predictability and simplicity. Frequency control frameworks should promote transparency and be predictable, so that market participants are informed about issues that affect system security and can make investment and operational decisions.

This approach, the assessment principles, and stakeholders' views on these are set out in more detail in section 4.3 of the draft report.

2.3.2 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, as set out in section 2.2, recent and potential 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.

As the power system continues to change, 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 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 draft report therefore set out the AEMC's views on the priority with which the identified issues should be addressed. Based on stakeholder feedback to the draft report, this final report moves away from categorising the issues as 'immediate priorities' and 'emerging needs', and instead sets out an ongoing program of work for the AEMC and AEMO to undertake alongside interested stakeholders to address the identified issues before or as they emerge.

This work plan is discussed in Chapter 3 as it relates to the progression of the issues identified in this review. It is set out in detail in Chapter 4.

3 AEMC'S RECOMMENDED CHANGES TO THE FREQUENCY CONTROL FRAMEWORKS

As explained in section 1.2, the AEMC divided its assessment of the issues identified in the terms of reference for the review into five key issues. These are:

1. Frequency control during normal operation.
2. Future FCAS frameworks.
3. Frequency monitoring and reporting, and forecasting.
4. Participation of distributed energy resources in system security frameworks.
5. AEMO's market ancillary services specification (MASS).

This chapter summarises the AEMC's analysis and conclusions on the five key issues. More detail, including stakeholder views, is set out in the relevant appendices to this report. The following chapter sets out the work plan that the AEMC, AEMO and the AER have developed to address these issues over the short to long term.

3.1 Frequency performance during normal operation

3.1.1 AEMC analysis and conclusions

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.

The draft report for this review set out:

- the consequences of deteriorating frequency performance
- the drivers of this deterioration
- an assessment of the materiality of the deterioration
- possible options to address the deterioration
- the AEMC's draft recommendations on which of those options are most likely to further the NEO.

In the draft report, the AEMC concluded that:

- the deterioration of frequency performance during normal operation is a material issue that warrants attention
- the deterioration could be addressed by, among other things, the provision of primary frequency control in the normal operating frequency band (termed a 'primary regulating response')
- the existing regulatory arrangements do not require or adequately incentivise the provision of a primary regulating response
- providers of a primary regulating response should be remunerated for the costs of doing so, in particular where the opportunity costs of maintaining the capacity to provide the

response (i.e. maintaining headroom to be able to increase output) are likely to be high.

Stakeholders largely supported these conclusions in their submissions to the draft report.

The draft report recommended two options to incentivise and reward the provision of a primary regulating response for further work and investigation:

1. The provision of a primary regulating response through the existing regulating FCAS markets.
2. Changes to the procedure by which AEMO recovers regulating FCAS costs (known as the 'causer pays procedure') to facilitate the provision of incentive payments for primary regulating response.[54]

The draft report also considered these options in the context of broader, longer-term changes to the existing FCAS market frameworks to appropriately value and incentivise the provision of frequency services as the power system changes.

Submissions to the draft report indicated that many stakeholders did not support the first option above because:

- such an approach would be unlikely to deliver suitable levels, or a sufficient distribution, of primary regulating response
- some participants may be unable to provide regulating FCAS and a primary regulating response, which would reduce the competitiveness of the market for regulating FCAS.

Of the two, stakeholders largely preferred the second option as an interim approach to addressing the deterioration while developing a more long-term solution.[55]

In its submission to the draft report, AEMO was of the view that "while a form of payment mechanism would be the most effective solution for the procurement of [a primary regulating response] in the longer-term, the design of any mechanism must build on the underlying technical needs of the system." AEMO explained its intention to conduct a range of actions by the end of 2018 to help it better understand the engineering requirements necessary to achieve effective frequency control. It therefore recommended that the AEMC consider the outcomes of those actions before putting in place any new regulatory or market arrangements to deliver a primary regulating response.

AEMO is undertaking a range of actions in an attempt to better understand the drivers of the deterioration of frequency performance under normal operating conditions, and to reverse this deterioration, or at the very least halt any further deterioration.

AEMO intends for these actions to be materially complete by the end of 2018. Specifically, AEMO is intending to:

- conduct a survey of generator frequency control settings (completed April 2018)
- conduct a trial of primary frequency control in Tasmania (completed May 2018)

54 The report also identified broader issues with this procedure and made some recommendations on how it could be improved.

55 A discussion of stakeholder views on the other options presented in the report is set out in [Appendix B].

- publish a revised causer pays procedure to remove aspects of it that may be discouraging the provision of a primary regulating response
- conduct AGC tuning
- investigate the need to increase the quantity of regulating FCAS on a static or dynamic basis, and doing so if necessary
- conduct a trial of primary frequency control in the mainland, building on experience from the Tasmanian trial undertaken in May 2018
- monitor and report quarterly on frequency outcomes, on a voluntary basis
- continue coordination of proposed changes to generator governor settings following the results of the survey conducted in April 2018.

AEMO advises that there is no immediate need to implement regulatory change to address the deterioration of frequency performance during normal operation before the results of these short term actions are known, and that current regulatory tools are expected to be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard within this timeframe.

While these actions may address the immediate deterioration of frequency performance under normal operation, they neither incentivise nor require the provision of a primary regulating response. As such, the AEMC is of the view that there is a need to find a more permanent solution to the issue. The AEMC's proposed approach to finding a longer-term approach to address this issue is set out in section 3.2. The AEMC's analysis of potential longer-term solutions is set out in detail in Appendix A. Further detailed commentary on stakeholder responses to the draft report in relation to frequency control during normal operation can be found in Appendix B.

This report therefore does not recommend any regulatory change to address the deterioration in the immediate term. Rather, it sets out a plan of work that includes AEMO undertaking the above actions. It is appropriate for the AEMC, AEMO and other stakeholders to understand the impact of these actions before considering any regulatory change.

The AEMC makes the recommendation set out below.

RECOMMENDATION 1: ARRANGEMENTS FOR THE PROVISION OF PRIMARY REGULATING SERVICES

In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

In order to develop such a mechanism, the Commission supports the trialling of changes to generator governor settings in Tasmania and the mainland, and associated technical investigations by AEMO, which are expected to be complete by December 2018.

The Commission recommends that the results of these trials and investigations be used to develop an explicit mechanism to incentivise the provision of a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

3.1.2 Relevant aspects of work plan

The AEMC, AEMO and the AER have developed a joint work plan to progress the recommendations arising from this review. This work plan is set out in full in Chapter 4.

Relevant aspects of the work plan that relate to Recommendation 1 and associated issues with the deterioration of frequency performance under normal operation include:

Short term (June – December 2018)

- AEMO implements the measures listed above by end 2018.
- AEMO reports on the outcomes of these actions as results become available, through its Ancillary Services Technical Advisory Group, Frequency Control Working Group and/or published reports.

Medium term (August 2018 – July 2019)

- AEMO assesses the effectiveness of its short-term actions at meeting the requirements of the frequency operating standard, and whether there is a need for an interim measure to be put in place before a longer term mechanism for the procurement of a primary regulating response comes into effect. Notwithstanding practical viability, potential interim measures may include:
  - those that might not require regulatory change (e.g. AEMO negotiating with generators or issuing directions
  - those that would likely require regulatory change (e.g. mandatory provision of primary frequency control, a new contracting arrangement or valuing positive contribution factors through the causer pays procedure).

AEMO monitors and reports on frequency performance outcomes with respect to the requirements of the frequency operating standard on an ongoing basis, as would be required by the proposed rule change recommended in this review.[56] The exact content and regularity of these reports would be determined through the rule change process. This reporting should take into account the impact of the commencement of the minimum fault level and inertia requirements.

3.2 Future FCAS frameworks

3.2.1 AEMC analysis and conclusions

The AEMC has examined the broader structure of the existing FCAS markets to determine:

- whether they will remain fit for purpose in the longer term

56 This recommendation is explained in [section 3.3].

- how to most appropriately incorporate FFR services, or enhance incentives for FFR services within the existing markets
- longer-term options to facilitate co-optimisation of energy, FCAS and inertia.

As the nature of electricity supply and demand in the NEM continues to change, there is expected to be a need to re-evaluate the design of the existing frequency control frameworks. While the design of the existing regulating and contingency FCAS markets has proved effective in optimising the efficient dispatch of FCAS sources in real time, new approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies in a way that delivers efficient outcomes for consumers.

There are a number of drivers of change in the current market environment that, at some point, may limit the ability of the existing FCAS market arrangements to continue to deliver efficient market outcomes in the interests of consumers. Specifically, the existing market arrangements:

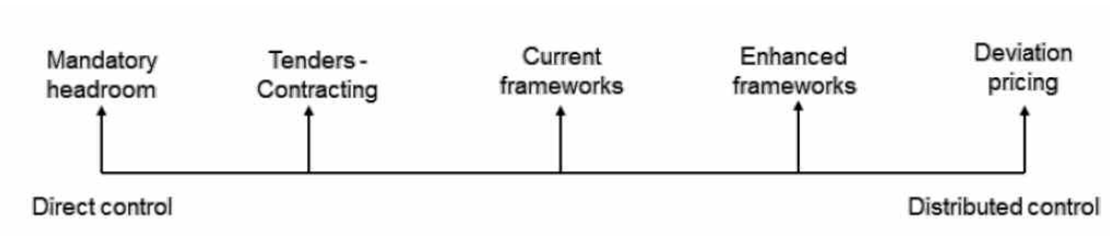
- do not place an explicit value on the provision of FFR services or inertia, and do not coordinate with the provision of other system services, such as system strength
- reflect a 'traditional' generation mix and therefore may not adequately support new technologies and the services needed as the power system changes
- may not provide longer-term investment certainty due to a lack of counterparties willing to hedge FCAS market risks
- do not provide incentives for market participants to reduce their potential impact on the need for frequency control services.

Appendix A of this report describes when, and in what form, the AEMC expects these deficiencies to become material, to inform the appropriate timeframes for making substantive changes.

Further, the current frequency control frameworks do not require or incentivise market participants to provide a primary regulating response to support good frequency control under normal operation. As noted in section 3.1, AEMO is undertaking a range of actions to better understand the drivers of the recently observed deterioration of frequency performance under normal operation, and to reverse this deterioration (or at the very least halt any further deterioration). While the actions might address the immediate deterioration, none of them establish any direct incentive or regulatory requirement for market participants to provide a primary regulating response. As such, regardless of whether AEMO's short term actions fix or halt the deterioration, the AEMC is of the view that there is a need to find a more permanent solution to the issue that is informed by the outcomes of AEMO's short-term actions, particularly its trials of primary frequency control in Tasmania and on the mainland.

The draft report set out a spectrum of frameworks (replicated below) for the procurement and dispatch of FCAS to address the deficiencies set out above. Each framework reflects a different level of control – from centralised (e.g. by AEMO) to distributed (e.g. by participants themselves). In this way, the spectrum represents a trade-off between higher levels of certainty and confidence in the maintenance of system security and increased efficiency and flexibility in the provision of services.

Figure 3.1: Spectrum of frequency control frameworks



The relevance of adjusting the existing FCAS frameworks towards either direction on the spectrum above can be informed by the extent to which the future requirements of the power system are met by any such change. That is, whether the approach:

- incentivises, requires or rewards the provision of frequency control services that are needed to meet the requirements of the frequency operating standard
- reduces barriers to the participation of emerging technologies and efficiently values service provision
- enables the co-optimisation of the provision of frequency control services with inertia
- coordinates the locational requirements of frequency control services and other system security constraints, such as system strength
- reduces the potential variability and unpredictability of supply and demand imbalances.

In the draft report, the AEMC concluded that the FCAS frameworks closer to the right side of the spectrum are better able to meet these needs because:

- they 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
- they do not require the provision of frequency control services to meet a pre-defined market specification and, as such, are generally technology neutral
- there is flexibility to vary the required frequency response over time to adapt to changing market conditions
- the potential lack of investment certainty may be ameliorated by the ability for market participants to enter into bilateral contracts
- they are likely to be better able to enable the co-optimisation of frequency control services with inertia and system strength as they have a higher degree of flexibility to dynamically adjust the mix of services required in real time than those on the left side of the spectrum.

While there were few detailed comments on this aspect of the draft report, there was general agreement among stakeholders that any future frequency control frameworks should be non-mandatory and market-based.

Appendix A of this report explores the need for a longer-term solution for the provision of a primary regulating response and sets out the AEMC's views on the criteria that should be used to design an appropriate mechanism. In short, the AEMC is of the view that the efficient and effective achievement of good frequency control is most likely to occur in circumstances where participants are rewarded or penalised consistent with the value of their actions on system frequency. That is, where:

- costs are imposed on those participants that cause frequency deviations
- payments are made to those participants that minimise frequency deviations.

Under such an approach, participants are incentivised to minimise actions that adversely affect system frequency and to undertake actions that support system frequency.

In order for such a policy mechanism to be efficient and effective, the following criteria must be satisfied:

- **Performance-based and dynamic** - Payments made to participants to support frequency, and charges to participants that contribute to frequency deviations, must be consistent with their actions and the value these actions provide to the system.
- **Transparent** – Participants must be provided with the means of understanding how their actions relate to the costs or rewards they are likely to incur.

Appendix A of this report explores potential new arrangements that could be introduced to meet these criteria and maintain the existing central procurement of regulating FCAS. This includes consideration of options proposed by stakeholders and a performance-based deviation pricing mechanism.

Under a deviation pricing approach, frequency control is undertaken by participants through a 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 structure.

The mechanism operates on the basis of a symmetric payment and cost recovery incentive framework. 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 frequency deviations away from 50 Hz. The net result is a balanced two-way system of payments and charges that provides an incentive for market participants to track the trajectory of their generation or load in a manner that supports system frequency.

A key feature of a deviation pricing mechanism is that it allows all frequency control technologies to be appropriately valued in accordance with the speed and profile of their response. The amount that is either paid by or charged to participants is proportional to the value of the response that they provide or the costs that they impose on the system respectively. In the AEMC's view, this mechanism could initially operate as an incentive for a primary regulating response within the normal operating frequency band, but could be extended to value contingency FCAS, FFR and inertia in the future.

This report does not recommend a particular approach. The AEMC recognises that further work and stakeholder consultation is required before deciding on and implementing a longer-term mechanism for the procurement of a primary regulating response and extending it to other frequency control services. Instead, this report sets out a work plan for the continued exploration and assessment of the range of market/incentive-based approaches to the provision of primary regulating response for the longer-term, informed by the results of AEMO's short-term actions to addressing the recent deterioration of frequency performance during normal operation.

3.2.2 Relevant aspects of work plan

The AEMC, AEMO and the AER have developed a joint work plan to progress the recommendations arising from this review. This work plan is set out in full in Chapter 4.

Relevant aspects of the work plan that relate to the consideration of a longer term mechanism for the procurement of a primary regulating response and other frequency control services include:

Complete

- 29 June 2018. AEMO published the system strength and inertia requirements methodologies, and minimum fault levels and minimum inertia levels for the NEM. These reports include that:
  - no inertia shortfalls have been identified in the NEM at this time
  - fault levels shortfalls have been identified at all three fault level nodes in South Australia
  - no fault level shortfalls have been identified outside of South Australia at this time
- 17 July 2018. AEMO published its Integrated System Plan, which sets out an assessment of the medium to long term needs of the power system with respect to frequency control (among other things).

Short-medium term (Aug 2018 – Jul 2019)

- The AEMC commences a detailed exploration of the range of market/incentive-based approaches to the provision of primary frequency control (and potentially other frequency services) for the longer-term, informed by approaches in international power systems and the options set out above in section 3.2.1. In consultation with AEMO and stakeholders, the AEMC determines the most efficient approach and avenues to its development and implementation. In parallel, the AEMC will consider how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard. This includes consideration of whether the NER or the frequency operating standard should:
  - prescribe in more detail the required frequency performance within the normal operating frequency band

    - include a system standard in relation to the rate of change of power system frequency.
- AEMO continues its work on assessing the longer-term needs of the power system, based on a holistic view of inertia, primary and secondary frequency control as well as other potential system needs (for example ramping availability).
    - AEMO's assessment will consider the system needs under various operating conditions, as well as the available technology capabilities during this time. This analysis will determine the characteristics of the frequency services that will be required, and inform the development of service specifications for market/incentive-based mechanisms.
    - The co-optimisation of these service specifications with energy dispatch will also be considered.
    - AEMO will work with market participants to trial capabilities under these anticipated network conditions.

Longer term (July 2019 – July 2020)

- The AEMC and AEMO assess how the longer-term approach identified in the work that the AEMC commenced in August 2018 is best implemented with respect to the other anticipated changes in frequency control needs of the power system. This will be informed by AEMO's work on the identification of system needs, frequency control trials in Tasmania and the mainland and any other broader proposed market design changes in the security and reliability space. If necessary the market/incentive-based mechanism for primary frequency control in the normal operating frequency band is further refined for implementation, which could involve:
    - development of new frameworks and associated cost-recovery mechanisms
    - identification of transition pathways from the existing frameworks to new or redesigned mechanisms
    - revision of associated regulatory frameworks
    - consideration of the potential to extend the mechanism to contingency frameworks and other system services, such as inertia and fast frequency response
    - phasing out / terminating any interim solutions that were implemented.

3.3 Frequency monitoring and reporting, and forecasting

3.3.1 AEMC analysis and conclusions

The AEMC has explored ways in which the existing frequency reporting, FCAS reporting and forecasting arrangements could be amended to enhance the operation of the existing frequency control frameworks.

Based on stakeholder input and the AEMC's own analysis, the AEMC has concluded that:

- there is a lack of transparency regarding the frequency performance of the power system under normal operating conditions
- there is a lack of transparency regarding the general performance of FCAS markets

- improvements to AEMO's supply and demand forecasting arrangements may help to drive better frequency outcomes.

Frequency performance of the power system

As explained in section 3.1, the frequency performance of the power system under normal operating conditions has been deteriorating in recent times. This has implications for power system security and for the operation of plant connected to the system. However, there is currently a lack of transparency regarding the frequency performance of the power system during normal operation. This is because the NER do not contain a requirement for AEMO to report regularly on power system frequency performance during normal operation.

AEMO currently produces frequency monitoring reports voluntarily on a periodic basis, and has committed to do so more regularly. However, as there is no requirement for AEMO to publish such reports, there is neither consistency in how often they are published nor formal consultation on what metrics are reported against.

The AEMC has concluded that there is potential to improve these arrangements so that:

- market participants are more regularly informed about issues that affect power system security, including whether the requirements of the frequency operating standard are being met
- current and future market participants are alerted to the need for FCAS and have access to information that helps them make investment and operational decisions
- the market can understand the impact of any changes made to improve frequency performance during normal operation.

The draft report recommended that a rule change request be submitted to amend the NER to require AEMO to monitor, and publish reports on, frequency outcomes with respect to the requirements of the frequency operating standard. All stakeholders that commented on this recommendation in their submission to the draft report supported it.

Informed by stakeholder input, the AEMC has further refined the recommendation with respect to the proposed frequency of reporting and the specific metrics that AEMO should report on. The AEMC makes the recommendation set out below.

RECOMMENDATION 2: AEMO REPORTING ON FREQUENCY PERFORMANCE

That the AER submit a rule change request in Q3 2018 to amend the NER to require AEMO to publish:

- weekly reports on frequency outcomes with respect to the frequency operating standard
- quarterly reports providing AEMO's analysis of key trends and specific events.

A change to the NER would be required to implement this obligation. Appendix C of this report sets out more detail and proposed rule drafting on how such an obligation could be given effect. The exact metrics to be reported against, and the required frequency of reporting, would be determined in consultation with stakeholders through a rule change process. For example, it may be more practical for AEMO to publish weekly reports on frequency outcomes with respect to the requirements of the frequency operating standard, and publish quarterly reports with further analysis on whether all the requirements of the frequency operating standard have been met.

FCAS market performance

FCAS market dynamics have changed significantly in recent times with the entry of new providers, and changes in the types of technologies providing FCAS. However, there is a lack of regular, readily available information and analysis about the general performance of FCAS markets. This is because the existing FCAS market reporting requirements in the NER are primarily related to individual events.

The AEMC has concluded that there is potential to improve these arrangements so that:

- market participants and other interested stakeholders have an understanding of how much it costs to meet the requirements of the frequency operating standard
- current and future market participants are alerted to the need for FCAS and have access to trend information that helps them make investment and operational decisions
- market participants and other interested stakeholders have a sense of whether the FCAS markets are efficient and effective.

The draft report recommended that a rule change request be submitted to amend the NER to require 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. All stakeholders that commented on this recommendation in their submission to the draft report supported it.

Informed by stakeholder input, the AEMC has further refined the recommendation with respect to the proposed frequency of reporting and the specific metrics that the AER should report on. The AEMC makes the recommendation set out below.

RECOMMENDATION 3: AER REPORTING ON FCAS MARKET OUTCOMES

That the AER submit a rule change request in Q3 2018 to amend the NER to require the AER to report quarterly on the performance of FCAS markets, specifically:

- the total costs of FCAS
- volumes (both enabled and utilised), prices, number of participants for each of the eight FCAS markets and the technology types of those participants
- commentary on key trends
- an assessment of whether the FCAS markets are effective.

A change to the NER would be required to implement this obligation. Appendix C of this report sets out more detail and proposed rule drafting on how such an obligation could be given effect. The exact metrics to be reported against, and the required frequency of reporting, would be determined in consultation with stakeholders through a rule change process. For example, it may be more appropriate or beneficial for stakeholders if the AER conducted its assessment of whether the FCAS markets on an annual basis, rather than quarterly.

Supply and demand forecasting

Forecasting is an integral part of NEM operations. Accurate forecasts help AEMO manage the supply/demand balance and keep frequency within the requirements of the frequency operating standard. However, changing technology and behaviour in the power system is leading to increased variability and unpredictability of supply and demand, which can make it harder for AEMO to meet the requirements of the frequency operating standard.

Sudden changes in output from non-dispatchable capacity[57] within a dispatch interval can increase the level of uncertainty in the dispatch process, which may increase the amount of FCAS needed to maintain frequency within the requirements of the frequency operating standard. Variations between supply and forecast demand within the five minute dispatch interval are what drives the use of regulating FCAS and brings about system security (rather than reliability) concerns.

Improvements to the accuracy of supply/demand 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. Nevertheless, forecasts will never be 100 per cent accurate, and at some point the costs and effort required to improve forecasting arrangements to gain a relatively small improvement in performance will outweigh the costs of mitigating the error via dispatching more regulating FCAS. The objective should therefore be to make dispatch demand forecasts as accurate as is efficient and use regulating FCAS to make up any difference. Submissions on the issues paper indicated that stakeholders generally agree with this conclusion.

On 26 July 2018 the AEMC published a final report on its *Reliability frameworks review*, which included, among other things, recommendations on ways in which AEMO's forecasting processes could be improved. While these proposed improvements were considered in the context of reliability timeframes – i.e. longer term forecasts as opposed to forecasts for the next dispatch interval – any changes that improve the accuracy of forecasting for reliability purposes are likely to have flow on impacts for the supply/demand balance within a dispatch interval, and thus support better frequency control.

This report concludes that one of the emerging drivers of variations between supply and demand within a dispatch interval is the unexpected, large, coordinated operation of distributed energy resources (e.g. a virtual power plant). A lack of awareness of where these resources are and how they operate may increase demand forecasting errors and

57 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.

thereby increase the enablement and use of regulating FCAS, and potentially contingency FCAS.

AEMO and the AEMC are undertaking a range of projects to address this and broader issues associated with the visibility and operation of distributed energy resources and virtual power plants. In light of this work, and the other initiatives being undertaken by AEMO to improve its forecasting, this report does not make any recommendations to address forecasting issues. The AEMC will continue its assessment of forecasting issues through its ongoing system security and reliability work program.

3.3.2 Relevant aspects of work plan

The AEMC, AEMO and the AER have developed a joint work plan to progress the recommendations arising from this review. This work plan is set out in full in Chapter 4.

Relevant aspects of the work plan that relate to Recommendations 2 and 3 include:

Short term (June – December 2018)

- Rule change requests submitted by the AER and made for earliest implementation (at least by Q1 2019) on:
  - AEMO monitoring and reporting of frequency performance
  - AER monitoring and reporting of FCAS market performance

Short-medium term (Aug 2018 – Jul 2019)

- Likely earliest commencement ofAEMO and AER obligations to report on frequency performance outcomes and the performance of FCAS markets. This assumes that the rule change requests are received immediately after publishing the *Frequency control frameworks review* final report and are commenced shortly thereafter.

3.4 Participation of distributed energy resources in system security frameworks

3.4.1 AEMC analysis and conclusions

Through this review the AEMC has explored:

- the potential for distributed energy resources to provide the services needed to maintain power system security, including FCAS
- whether there are any regulatory barriers that prevent distributed energy resources from providing FCAS or other system security services and, where those barriers are inefficient or unnecessary, ways in which they could be addressed.

As described in Chapter 2, theelectricity 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. 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 opportunities and challenges for 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.

A number of recent developments have demonstrated a growing interest in aggregating distributed energy resources to provide services at a wholesale level. These include:

- recent announcements from governments and retailers about virtual power plants
- pilots and trials being undertaken by ARENA and funding recipients to test a range of issues related to distributed energy resources
- the registration of two participants as Market Ancillary Service Providers, who can aggregate load for participation in FCAS markets.

This ongoing transformation of the power system provides the context for a review of the regulatory frameworks governing the provision of system security services. As the uptake of distributed energy resources continues, particularly in an aggregated manner, it is important that system security frameworks facilitate distributed energy resources contributing to power system security where they are able to do so.

Through this review and with stakeholder input, the AEMC 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 are set out below.

Registration categories for aggregated distributed energy resources

There are two existing frameworks in the NER that provide for the aggregation of distributed energy resources – the Market Ancillary Service Provider framework and the Small Generation Aggregator framework.

There do not appear to be any barriers in the NER to prevent a Small Generation Aggregator or a Market Ancillary Service Provider from tendering or applying to AEMO to provide non-market ancillary services.[58] However, the NER do not accommodate the aggregation of small generating units (e.g. distributed energy resources) by Small Generation Aggregators 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 by Small Generation Aggregators to offer FCAS.

In addition, the NER and the MASS does not set out clearly that a Market Ancillary Service Provider can provide market ancillary services in relation to load under its control by aggregating small generating units behind the connection point to affect the level of that load.

Amending the existing Market Ancillary Service Provider and Small Generation Aggregator frameworks to clarify that they are able (in the case of Market Ancillary Service Providers) or to enable them (in the case of Small Generation Aggregators) to offer market ancillary services from small generating units would have the benefits of:

58 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 or NSPs. 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.

- increasing competition in FCAS markets, potentially leading to lower FCAS costs
- diversifying the providers of these services
- providing greater value to the owners of distributed energy resources
- providing signals for more efficient operational and investment signals to the owners and operators of distributed energy resources.

Stakeholders largely supported these conclusions in their submissions to the draft report.

There are likely to be technical challenges arising from the participation of aggregated small generating units in providing FCAS. For example, the provision of FCAS via a large, fleet of aggregated distributed energy resources may have localised network impacts (e.g. on voltage) or may in fact negatively impact power system security.

There is a range of regulatory challenges associated with emerging business models, such as virtual power plants, that are not entirely addressed by recommended changes to the existing aggregator frameworks. Broader technical and regulatory impacts of aggregated distributed energy resources are being explored through several pieces of work, including those set out below:

- The AEMC is working with AEMO to develop a joint work program on distributed energy resources with the objective of better coordinating the various areas of work that the AEMC and AEMO are undertaking on a range of distributed energy resources-related issues. One aspect of this work program is a collaboration between AEMO, the AEMC and the AER to establish a NEM virtual power plant trial program. The trials will be used to support an understanding of the technical and regulatory requirements associated with virtual power plants providing energy, FCAS and network support services. The intention is that the trials will inform any future amendments to the regulatory framework to enable the power system and consumer benefits virtual power plants can offer.
- ARENA has a funding round on foot to support:
  - demonstration projects that improve the network hosting capacity of distributed energy resources
  - studies that contribute to improved integration of distributed energy resources.[59]

While the AEMC is of the view that there is value in changing the existing frameworks for aggregation in the short term, these rule changes may be more appropriately considered when the outcomes of the work set out above are more advanced.

The AEMC makes the recommendation set out below.

RECOMMENDATION 4: AGGREGATOR REGULATORY FRAMEWORKS

That AEMO submit a rule change request to:

59 See: https://arena.gov.au/funding/programs/advancing-renewables-program/distributed-energy-resources/

1. clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units
2. enable 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 the MASS.

Connection frameworks and Australian Standard 4777

The connection arrangements set out in Chapter 5A of the NER establish the obligations and processes by which retail customers, including those with distributed energy resources, connect to a distribution network. However, these arrangements do not contain any specific requirements or guidance on the actual technical specifications of connections by retail customers to distribution networks. The AEMC is of the view that this lack of prescription has resulted in connection frameworks across DNSPs being inconsistent, lacking in transparency and lacking justification for costs and technical requirements imposed in the connection process.

The technical requirements imposed through DNSPs' connection arrangements and AS 4777[60] may result in distributed energy resources having the capability to provide system security services, such as an increase in power in response to a drop in frequency, or voltage support. However, they do not appear to value or incentivise the provision of such services. Further, some of these requirements may actually impede the ability of distributed energy resources to provide system security services.

The efficient uptake of distributed energy resources is supported when technical requirements are clear, proportionate and relevant to what is being connected and how it will be operated. Most stakeholders supported this conclusion in their submissions to the draft report.

It is important that DNSPs have the discretion in the connection process to address risks to the security and safety of the power system. However, the connection arrangements:

- should 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)
- should not provide DNSPs with monopoly access to services that can be provided by distributed energy resources.

Energy Networks Australia is in the process of establishing a set of nationally-consistent grid connection guidelines for distributed energy resources, in recognition that DNSPs "have responded to the challenges of the growth in rooftop solar and storage options by adopting their own – often different – technical requirements and connection processes".[61]

60 Australian Standard (AS) 4777 applies to low voltage inverters connected to the power system, which includes inverters for grid-connected solar PV systems and battery storage systems.

61 See: https://www.energynetworks.com.au/sites/default/files/010618_ena_der_guidelines_0.pdf

The ultimate aim of the guidelines is to “support the fair and efficient connection of solar and battery storage to the grid.” The AEMC supports this work and will continue to provide input as the guidelines are developed.

The AEMC acknowledges the concerns raised by some stakeholders that the guidelines will not be binding and may result in a ‘lowest common denominator’ approach to network connections. Nevertheless, the AEMC recommends that, in the first instance, stakeholders engage in the development of the Energy Networks Australia guidelines to attempt to have these concerns addressed. If they are not addressed, consideration of further prescription in the NER regarding the connection of distributed energy resources may be warranted.

The AEMC makes the recommendation set out below.

RECOMMENDATION 5: CONNECTION ARRANGEMENTS AND AS 4777

That Energy Networks Australia, in developing its national connection guidelines, explicitly consider:

- 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 circumstances in which it is appropriate to limit the size of the connection, why it might be appropriate to limit the size of the connection and how this applies to hybrid systems
- the extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services or participate in other energy markets.

The Commission encourages stakeholders to input into the development of these guidelines.

Technical interactions between distributed energy resources and the rest of the power system

For distributed energy resources to provide system security services:

- the local network conditions must be such that the provision of the service can physically be accommodated
- the provision of the service should not cause the power system to become insecure, or prevent the DNSP from being able to meet its service obligations.

AEMO has a range of work underway to understand and mitigate the impacts of distributed energy resources on power system security. While not the focus of this review, stakeholders raised two main concerns with the provision of services from distributed energy resources:

1. Local network conditions may affect the ability for distributed energy resources to provide system security services. Specifically, the distribution network needs sufficient

thermal and network capacity prior to the provision of services to accommodate additional active or reactive power.

2. Distributed energy resources providing system security services are likely to have an impact on local network conditions. The provision of services within the distribution network should not prevent the DNSP from being able to meet its service obligations.

However, the technical challenges associated with the provision of system security services within a distribution network are not well understood. 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.

There is currently limited visibility of the spare capacity in distribution networks and of the quantity or intentions of the growing amount of distributed energy resources. Increasing this visibility will be crucial to unlocking the potential for distributed energy resources to provide system security services (and other services) while also enabling NSPs to meet their service obligations.

Trials coordinated by AEMO, NSPs and aggregators of distributed energy resources are likely to support an understanding of the challenges of doing so, and of how these challenges could be addressed. Stakeholders largely agreed with this conclusion in their submissions to the draft report, and highlighted the importance of sharing information on the challenges and potential solutions to these issues.

The AEMC makes the recommendation set out below.

RECOMMENDATION 6: TECHNICAL INTERACTIONS BETWEEN DISTRIBUTED ENERGY RESOURCES AND THE NETWORK

That:

1. when AEMO conducts trials of aggregated distributed energy resources providing FCAS, including virtual power plants, it assesses 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
2. when undertaking these trials, AEMO collaborate with interested and affected stakeholders, including ARENA, the local DNSP, distributed energy resource aggregators, virtual power plant, neighbouring DNSPs and affected TNSPs
3. 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.

3.4.2 Relevant aspects of work plan

The AEMC, AEMO and the AER have developed a joint work plan to progress the recommendations arising from this review. This work plan is set out in full in Chapter 4.

Relevant aspects of the work plan that relate to Recommendations 4, 5 and 6 include:

Short term (June – December 2018)

- AEMO, the AEMC and the AER establish a NEM virtual power plant trial program to support an understanding of the technical and regulatory requirements associated with virtual power plants providing FCAS, as well as energy and network support services. This work will inform AEMO's review of the MASS and the AEMC's ongoing work on removing barriers to distributed energy resources participating in wholesale markets.
- Rule change request submitted (by AEMO) and made to allow Small Generation Aggregators to classify small generating units as market ancillary service generating units for the purposes of providing market ancillary services, and to clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units. This rule change request will be informed by the outcomes of the NEM virtual power plant trial program described above.

Short-medium term (Aug 2018 – Jul 2019)

- Likely earliest possible finalisation of rule change requests allowing Small Generation Aggregators to provide market ancillary services using small generating units, and clarifying that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units. AEMO may need to revise the MASS following the conclusion of those rule change processes, or in parallel, to give effect to any such rules (unless these revisions were captured by the MASS review that commences in August 2018 or any review conducted as a result of AEMO's trials of distributed energy resources providing FCAS).

3.5 AEMO's market ancillary services specification

3.5.1 AEMC analysis and conclusions

Through this review the AEMC has explored whether there are aspects of AEMO's MASS that could be amended to facilitate and better value the provision of FCAS from new technologies, including storage, aggregated distributed energy resources and demand response.

The MASS underlies the provision of market ancillary services (i.e. FCAS) in the NEM. It sets out the detailed specification of each of the market ancillary services and how a market participant's performance is measured and verified when providing these services.

The MASS has received increased attention of late. This has been driven by:

- higher FCAS prices, which encourages new participants to register to provide FCAS and therefore means they must meet the requirements of the MASS
- challenges encountered by participants seeking to provide FCAS using newer technologies that have traditionally not provided FCAS (e.g. battery storage and aggregated distributed energy resources) and are therefore not explicitly considered in the MASS.

In the draft report, the AEMC concluded that there are changes that could be made to the MASS to facilitate or better value the provision of market ancillary services from new sources, including batteries, aggregated distributed energy resources and demand response. Possible changes to the MASS were presented in two work streams:

- The participation of distributed energy resources in system security frameworks. Certain aspects of the MASS were flagged as potentially constituting an unnecessary barrier to distributed energy resources providing market ancillary services.
- Future FCAS frameworks. The detailed technical specification of each of the market ancillary services is set out in the MASS, including the times associated with the fast, slow and delayed contingency services. The AEMC noted that AEMO could amend the times associated with these services to support the provision of a frequency response faster than the existing fast contingency services, without needing changes to the NER.

The AEMC has combined these two considerations into a broader look at the MASS for the purposes of this final report.

AEMO has indicated an intention to commence a review of the MASS in August 2018, which will focus on refining expectations for how services should be delivered. The AEMC supports AEMO conducting a broader review of the MASS to determine whether it will remain fit for purpose as the power system changes. Stakeholders were also generally supportive of a review of the MASS to better incorporate newer technologies in their submissions to the draft report.

AEMO has also indicated an intention to conduct trials of aggregated distributed energy resources to test:

- the ability for distributed energy resources to participate in all eight FCAS markets
- the capability for distributed energy resources to provide services faster than existing FCAS (which could then in turn inform changes to how FCAS are specified in the MASS)
- how to efficiently measure and verify FCAS provision from aggregated distributed energy resources (including sampling across a set number of units with high-speed monitoring).[62]

In their submissions to the draft report, most stakeholders supported trials to test the capability of distributed energy resources and to inform AEMO's review of the MASS. The AEMC also agrees that there is value in AEMO conducting trials to test some of these issues. As noted previously, AEMO, the AEMC and the AER are collaborating to establish a NEM

62 AEMO, submission to draft report, p. 11.

virtual power plant trial program. The trials will be used to support an understanding of the technical and regulatory requirements associated with aggregated distributed energy resources providing energy, FCAS and network support services. The intention is that the trials will inform any future amendments to the regulatory framework to enable the power system and consumer benefits virtual power plants can offer.

Using stakeholder input and its own analysis, the AEMC is of the view that there may be aspects of the existing MASS that are inefficiently limiting participation in FCAS markets by newer technologies and undervaluing their response capabilities. The terms of reference for AEMO's proposed review of the MASS are not currently available. As such, this report highlights, and makes a recommendation on, aspects of the MASS that should be considered and consulted on through any such review.

The AEMC makes the recommendation set out below.

RECOMMENDATION 7: MARKET ANCILLARY SERVICES SPECIFICATION

That AEMO:

1. undertake trials of distributed energy resources providing FCAS, including virtual power plants, 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 and incorporating the outcomes of the trials (and any other trials of new technologies providing FCAS) into a review of the MASS.
2. conduct a broader review of the MASS that seeks to address any unnecessary barriers to new entrants, or any aspects of the MASS that may not appropriately value services provided by newer technologies where these services are valuable to maintaining power system frequency. This should include consideration of:
   a. the timing specifications for each of the different FCAS
   b. the overlapping interactions between the different FCAS specifications.
   c. any changes that may be necessary to settings within the MASS
   d. issues raised in the most recent review of the MASS that were considered out of scope.

Appendix E of this report sets out each aspect of the recommendation in more detail.

3.5.2 Relevant aspects of work plan

The AEMC, AEMO and the AER have developed a joint work plan to progress the recommendations arising from this review. This work plan is set out in full in Chapter 4.

Relevant aspects of the work plan that relate to Recommendation 7 include:

Short term (June – December 2018)

- AEMO, the AEMC and the AER establish a NEM virtual power plant program to support an understanding of the technical and regulatory requirements associated with virtual power plants providing FCAS, as well as energy and network support services. This work will inform AEMO's review of the MASS and the AEMC's ongoing work on removing barriers to distributed energy resources participating in wholesale markets.

- AEMO commences a review of the MASS, which focuses on refining expectations for how services should be delivered (priorities, shape, sustain, etc).

4 WORK PLAN FOR FREQUENCY CONTROL IN THE NEM

This chapter sets out a plan of proposed actions to be undertaken by the AEMC and AEMO, in consultation with stakeholders, to implement the recommendations made in Chapter 3 and address other emerging frequency control issues from now into the long term.

It was developed collaboratively by the AEMC, AEMO and the AER. The dates associated with each action are intended to provide indicative guidance to stakeholders. Ultimately, the timing of each action will depend on the resourcing capabilities of the AEMC, AEMO and the AER, and the statutory timeframes associated with any rule change processes. Further, the content of the work plan will be further shaped by the findings of each stage as it is progressed.

The Commission has concluded this stage of this review and has made a number of recommendations to improve frequency control in the NEM. However, the report has identified issues which still need to be addressed, together with a longer term collaborative work plan, which will provide a vehicle for:

1. the AEMC, AEMO and the AER to implement the various actions in the work plan below, and report on progress against those actions
2. the AEMC to further explore, and seek stakeholder input on, potential longer-term mechanisms for the procurement of a primary regulating response and other frequency services as the needs of the power system evolve.
3. the AEMC to consider, and consult with stakeholders on, how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard, which will include consideration of whether the NER or the frequency operating standard should:
    a. include a system standard in relation to the rate of change of power system frequency.
    b. prescribe in more detail the required frequency performance within the normal operating frequency band.[63]

As explained in section 1.6, the AEMC will continue the technical working group that was established for this review. The working group will provide a valuable means for the AEMC to gain input and feedback on the three items above.

The work plan in Table 4.1 below sets out proposed actions to be undertaken by the AEMC, AEMO and the AER to address a range of frequency control issues from now into the long term. It has been developed collaboratively by AEMC, AEMO and AER staff. The dates associated with each action are intended to provide indicative guidance to stakeholders. Ultimately, the timing of each action will depend on the resourcing capabilities of the AEMC and AEMO, and the statutory timeframes associated with any rule change processes.

63 This issue was raised in submissions to the issues paper for the Reliability Panel's Review of the frequency operating standard. However the Commission considers that the inclusion of a system standard in relation to the rate of change of power system frequency is related to the structure of the frequency operating standard and is more appropriately considered by the Commission as part of a broader review of frequency control frameworks. See submissions to the Reliability Panel Review of the frequency operating standard - Issues paper: ENA, p. 5; Engie, p. 5; SA Government, p. 7; TasNetworks, pp. 8-9.

Further, the content of the work plan will be further shaped by the findings of each stage as it is progressed.

AEMO is undertaking a range of actions in an attempt to:

- better understand the drivers of the recently observed deterioration of frequency control performance
- reverse this deterioration, or at the very least halt any further deterioration.

AEMO advises that there is no immediate need to implement regulatory change to address the deterioration of frequency control performance under normal operation before the results of these short term actions are known, and that current regulatory tools are expected to be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard within this timeframe.

Table 4.1: **Work plan for frequency control in the NEM**

TIMING	ACTION
	COMPLETED These actions were complete at the time of publication of this final report.
April 2018	AEMO conducted a survey of generator frequency control settings. The survey concentrated on technical control system parameters, but of key importance to frequency performance it indicated those units normally operating with 'tight' or 'wide' governor dead bands, and the circumstances under which different modes are used. The results of this survey will be used by AEMO in: • informing development of primary frequency control requirements (volume, dead bands, droops, etc.) • assessing various observed frequency behaviours such as apparent seasonality in frequency control performance • assessing the level of primary frequency control being provided by remaining generators • identifying those generators at increased risk due to frequency variation.
May 2018	AEMO conducted a trial on primary frequency control in Tasmania. Further information on the results of this trial is available in Appendix A of the final report for the *Frequency control frameworks review.*
22 May 2018	AEMO presented on the short term measures it has planned to do by the end of 2018 to members of the AEMC's technical working group for the *Frequency control frameworks review*.
26 July 2018	AEMC published the final report on the *Frequency control frameworks review*.
29 Jun 2018	AEMO published the system strength and inertia requirements methodologies and minimum fault levels and minimum inertia levels for the NEM. These reports include

TIMING	ACTION
	that: • no inertia shortfalls have been identified in the NEM at this time • fault level shortfalls have been identified at all three fault level nodes in South Australia • no fault level short falls have been identified outside of South Australia at this time.
17 Jul 2018	AEMO published its Integrated System Plan, which sets out an assessment of the medium to long term needs of the power system with respect to frequency control (among other things).
SHORT TERM (JULY - DECEMBER 2018)	
During this period, AEMO undertakes a range of actions to better understand the drivers of the recently observed deterioration of frequency control performance and reverse this deterioration (or at the very least halt any further deterioration). This period also sees the commencement of trials and new projects, and the submission of rule change requests, as recommended in the *Frequency control frameworks review* to better understand and address issues with the current regulatory and market arrangements for frequency control.	
August 2018	AEMO publishes a revised causer pays procedure that promotes clarity and removes intervals where the frequency indicator (FI) and actual frequency are mismatched, and publishes FI data closer to real time.
August 2018	AEMO commences a review of the market ancillary services specification (MASS), which focuses on refining expectations for how services should be delivered (priorities, shape, sustain, etc).

TIMING	ACTION
Q3 2018	AEMO, the AEMC and the AER establish a NEM virtual power plant trial program to support an understanding of the technical and regulatory requirements associated with virtual power plants providing FCAS, as well as energy and network support services. This work will inform AEMO's review of the MASS and the AEMC's ongoing work on removing barriers to distributed energy resources participating in wholesale markets.
Q3 2018	Rule change requests submitted by the AER and made on: • AEMO monitoring and reporting of frequency performance • AER monitoring and reporting on FCAS market performance for earliest implementation (at least by Q1 2019).
Late 2018	AEMO conducts AGC tuning as part of upgrade of its energy management system software.
Late 2018	AEMO investigates the need to increase the quantity of regulating FCAS on a static or dynamic basis (subject to consideration of quantity, timing and likely cost impact), and does so if necessary.
By end 2018	AEMO aims to complete a trial of revised primary frequency control in the mainland, building on experience from Tasmanian trial.
By end 2018	Reliability Panel publishes a draft determination on stage two of the *Review of the frequency operating standard*, which will include a thorough review of the settings contained in the standard.
Ongoing	AEMO monitors and reports on frequency outcomes on a voluntary basis (quarterly).
Ongoing	AEMO continues coordination of proposed changes to generator governor settings following results of the survey conducted in April 2018.
Ongoing	AEMO reports on the outcomes of the actions set out above as results become available

TIMING	ACTION
	through its Ancillary Services Technical Advisory Group, Frequency Control Working Group and/or published reports.
SHORT-MEDIUM TERM (AUGUST 2018 - JULY 2019) During this period, AEMO continues to assess and communicate the effectiveness of its actions in meeting the frequency requirements of the system. AEMO continues its work on assessing the longer term needs of the power system, which informs the AEMC's work on longer-term arrangements for frequency control.	
Ongoing	AEMO assesses the effectiveness of its short term actions at meeting the requirements of the frequency operating standard, and communicates whether there is a need to implement interim measures before a longer-term mechanism for primary frequency control within the normal operating frequency band comes into effect. AEMO and the AEMC will agree on whether there are any additional metrics or principles against which this decision should be assessed, e.g. the principles of good frequency control as set out in the draft report for the *Frequency control frameworks review*. Notwithstanding practical viability, potential interim measures may include: • those that might not require regulatory change (e.g. AEMO negotiating with generators, contracting through NSCAS framework or issuing directions) • those that would likely require regulatory change (e.g. mandatory provision of primary frequency control, a new contracting arrangement or valuing positive contribution factors through the causer pays procedure).
From August 2018	The AEMC commences a detailed exploration of the range of market/incentive-based approaches to the provision of primary frequency control during normal operation (and potentially other frequency services) for the longer-term, informed by approaches in international power systems. In consultation with AEMO and stakeholders, the AEMC determines the most efficient approach and avenues to its development and

TIMING	ACTION
	implementation. In parallel, the AEMC will consider how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard. This includes consideration of whether the NER or the frequency operating standard should: • prescribe in more detail the required frequency performance within the normal operating frequency band • include a system standard in relation to the rate of change of power system frequency.
From August 2018	AEMO continues its work on assessing the longer-term needs of the power system, based on a holistic view of inertia, primary and secondary frequency control as well as potential new needs to address ramping that occurs over multiple dispatch periods. • AEMO's assessment will consider the system needs under various operating conditions, as well as the available technology capabilities during this time. This analysis will determine the characteristics of the frequency services that will be required, and inform the development of service specifications for market/incentive-based mechanisms. • The co-optimisation of these service specifications with energy dispatch will also be considered. • AEMO will work with market participants to trial capabilities under these anticipated network conditions.
January 2019	Likely earliest commencement ofAEMO and AER obligations to report on frequency performance outcomes and the performance of FCAS markets. This assumes that the rule change requests are received immediately after publishing the *Frequency control frameworks review* final report and are commenced shortly thereafter.

TIMING	ACTION
Q1 2019	Rule change request submitted (by AEMO) and made to allow Small Generation Aggregators to classify small generating units as market ancillary service generating units for the purposes of providing market ancillary services, and to clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units. This rule change request will be informed by the outcomes of the NEM virtual power plant trial program described above.
Q1 2019	Likely earliest possible finalisation of rule change requests allowing Small Generation Aggregators to provide market ancillary services using small generating units, and clarifying that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units. AEMO may need to revise the MASS following the conclusion of these rule change processes, or in parallel, to give effect to any such rules (unless these revisions were captured by the MASS review that commenced in August 2018 or any review conducted as a result of AEMO's trials of distributed energy resources providing FCAS).
Q1 2019	Reliability Panel publishes final determination on stage two of the *Review of the frequency operating standard*.
Ongoing	AEMO produces frequency performance reports, as required by new monitoring and reporting rule, which report on whether the requirements of the frequency operating standard are being met. The exact content and regularity of these reports would be determined through the rule change process. This reporting should take into account the impact of the commencement of the minimum fault level and inertia requirements.
Ongoing	AER produces FCAS market performance reports, as required by new monitoring and reporting rule. Exact content and regularity of these reports would be determined through the rule change process.

TIMING	ACTION
	LONGER TERM (JULY 2019 – JULY 2020) During this period, AEMO and the AEMC work together, and with stakeholders, to further refine and implement a longer-term approach to frequency control.
Following completion of the AEMC's review of longer-term options and AEMO's assessment of system needs	The AEMC and AEMO assess how the longer-term approach identified in the work that the AEMC commenced in August 2018 is best implemented with respect to the other anticipated changes in frequency control needs of the power system. This will be informed by AEMO's work on the identification of system needs, frequency control trials in Tasmania and the mainland and any other broader proposed market design changes in the security and reliability space. If necessary the market/incentive-based mechanism for primary frequency control in the normal operating frequency band is further refined for implementation, which could involve: • development of new frameworks and associated cost-recovery mechanisms • identification of transition pathways from the existing frameworks to new or redesigned mechanisms • revision of associated regulatory frameworks • consideration of the potential to extend the mechanism to contingency frameworks and other system services, such as inertia and fast frequency response • phasing out / terminating any interim solutions that were implemented.

A POLICY OPTIONS FOR FREQUENCY CONTROL DURING NORMAL OPERATION AND FUTURE FCAS FRAMEWORKS

This appendix relates to the Commission's consideration of potential future FCAS frameworks, including the longer term approach to frequency control under normal operation. The Commission has sought to identify existing and potential deficiencies in the FCAS market arrangements, and potential new ways to procure and dispatch FCAS to meet the system's needs as it changes.

This appendix sets out:

- the AEMC's conclusions and recommendations on frequency control frameworks that were set out in the draft report
- a summary of stakeholder views on those conclusions and recommendations, based on submissions to the draft report
- the Commission's analysis of potential options for long term changes to frequency control frameworks
- a work plan for addressing the deterioration in frequency performance under normal operating conditions and making longer term changes to frequency control frameworks.

A.1 Deficiencies of the existing frequency control frameworks

In the draft report, the AEMC concluded that the design of the existing regulating and contingency FCAS markets has proved effective in optimising the efficient dispatch of FCAS sources in real time. However, we also noted the potential limitations of these arrangements as the electricity system changes.

In the immediate term, we are seeing a deterioration of frequency performance under normal operating conditions. This deterioration has arisen primarily due to a lack of incentives for market participants to provide primary frequency control in the normal operating frequency band.

- Section A.1.1 describes the observed deterioration of frequency performance during normal operation.
- Section A.1.2 describes the causes for the deterioration of frequency performance during normal operation.

The draft report also set out the Commission's views on some of the broader longer-term deficiencies of the existing frameworks for frequency control. As the nature of electricity supply and demand in the NEM continues to change, there will be a need to re-evaluate the design of the existing frequency control frameworks. New approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies in a way that delivers efficient outcomes for consumers.

- Section A.1.3 discusses potential future issues in relation to frequency control following contingency events and the coordination with other system services such as inertia and FFR.
- Section A.1.4 describes the potential timeframes for the incorporation of new ancillary services to help manage frequency in the NEM.

A.1.1 Deterioration of frequency performance under normal operating conditions

As set out in the draft report for the *Frequency control frameworks review*, the frequency performance in the NEM under normal operating conditions has degraded in recent times. 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 performance in the NEM under normal operating conditions prepared for AEMO by DIgSILENT.[64]

This issue was initially highlighted by Pacific Hydro in its submission to the Commission's Interim Report for the System security market frameworks review.[65] In its submission, Pacific Hydro highlighted the extent to which frequency has changed by comparing the system wide frequency profile on 8 May 2016 relative to the same day in 2001.[66]

This comparison is shown below in Figure A.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.

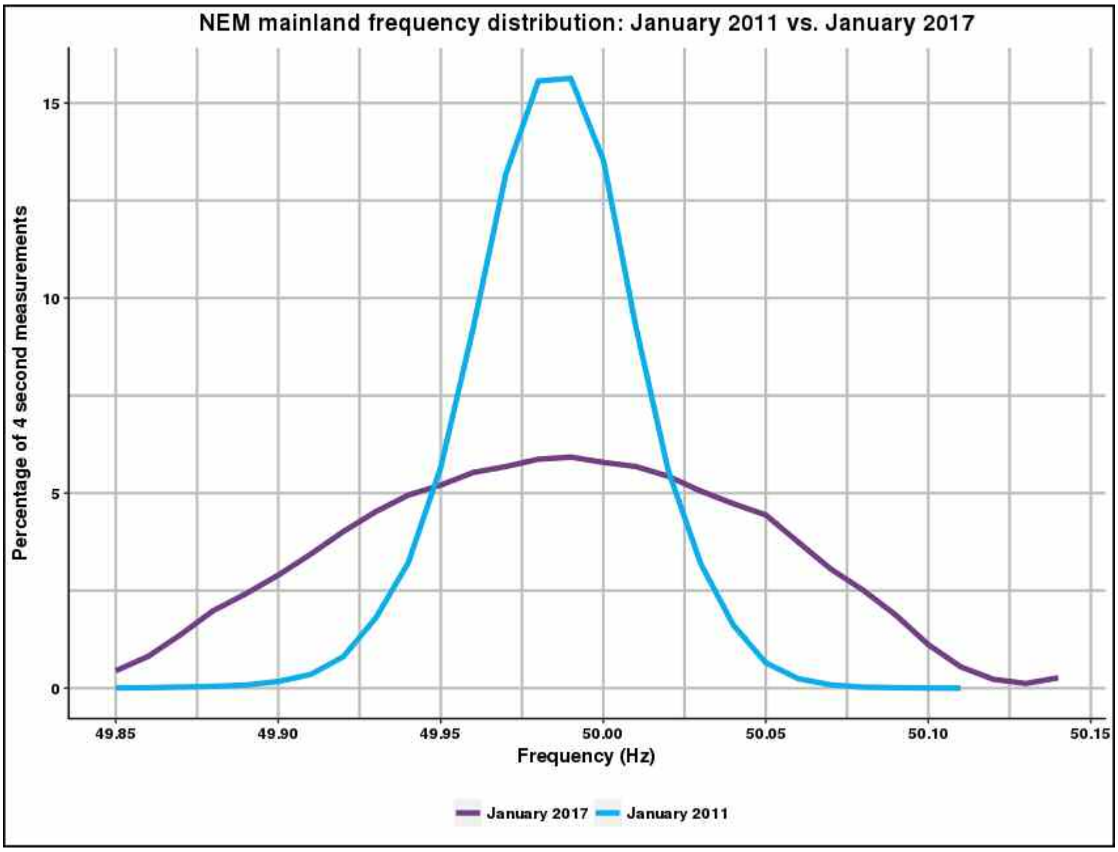
The Commission notes that, in this example, both frequency profiles demonstrate outcomes that are compliant with the frequency operating standard, in that the amount of time that the frequency is outside of the normal operating frequency band (49.85 – 50.15Hz) is less than one per cent.

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

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

66 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.

Figure A.1: Frequency distribution profile NEM mainland: Jan 2011 – Jan 2017



Source: AEMC analysis of 4 second frequency data provided by AEMO.

The power system frequency has increasingly operated further away from the nominal frequency of 50 Hz than has historically been the case. So far, excluding contingency events, the mainland frequency has been maintained within the normal operating frequency band for at least 99% of the time consistent with the frequency operating standard. This requirement was not met in Tasmania from February 2016 to February 2018, with the exception of August and September 2016.[67]

DIgSILENT identified a number of consequences of deteriorating frequency performance, including:[68]

- increased wear and tear on plant due to excessive movement caused by frequency deviations

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

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

- 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.

Further detail on the recent degradation of frequency performance during normal operation can be found in Appendix F of the draft report for the *Frequency control frameworks review*.

A.1.2 Causes of the deterioration of frequency performance under normal operating conditions

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. The draft report set out the AEMC's conclusions on the drivers of this degradation, which included generators decreasing or removing their responsiveness to frequency deviations within the normal operating frequency band by:

- widening their governor dead band such that they are unresponsive to frequency changes until the frequency moves outside the normal operating frequency band
- upgrading older mechanical governors to digital control systems, which enable a generator to easily change the frequency response mode of the generator and the dead band and droop characteristics, or
- where it is more difficult or costly to change governor settings and uneconomic to upgrade to digital systems, installing secondary control systems to dampen primary governor response.

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.[69]

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 exposure to causer pays events.[70] Similarly, Stanwell note that there has been an observed reduction in the provision by generators of a free primary frequency response.[71]

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

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

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

Generators are making these changes because there is no regulatory requirement for them to provide primary frequency control in the normal operating frequency band, nor is there any direct incentive for them to do so. As such, the only primary frequency control that is provided in the normal operating frequency band is done so voluntarily. However, governor response represents a cost in terms of wear and tear and efficiency. As some generators reduce or remove their responsiveness to frequency deviations in the normal operating frequency band, those that remain experience a greater impact on plant operation.

There are two principal aspects of the current regulatory arrangements that contribute to scheduled generators choosing to decrease or remove their responsiveness to frequency deviations within the normal operating frequency band. These are discussed further below and include:

- the lack of a direct financial incentive to cover the costs of providing a primary frequency response. These costs include the opportunity costs of maintaining headroom to be able to provide a frequency response and the direct operational costs of providing the frequency response.
- the current cost recovery arrangements for regulating FCAS (causer pays), which has failed to provide sufficient incentives to ensure adequate primary frequency control during normal operation.

Cost to generators of providing a frequency response

A generator's actions to support good frequency control, while providing value to the system, involves a cost to that participant. This cost includes:

- Direct cost impacts associated with being frequency responsive due to increased fuel consumption related to variable output as the generator responds to frequency variations, and increased variable operation and maintenance costs, due to potentially working the generator harder as it follows frequency variations.
- Opportunity costs associated with foregone generation where a generator is required to maintain headroom to provide a response.

There is some evidence to suggest that the costs on individual participants providing frequency response within the normal operating band reduces considerably when a number of other generating units are providing frequency response.[72]

AEMO has recently undertaken a survey of generator frequency control settings and is looking to publish results, which may provide further information on the likely impacts to different participants. AEMO has also conducted frequency control trials on in Tasmania, with a view to conducting a mainland trial before the end of 2018. AEMO provided the

72 Work undertaken by DIgSILENT suggests 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. This is supported by advice received from Nick Miller that the operational costs associated with the provision of primary frequency response by synchronous generating units are likely to be negligible when compared to other factors like variation in fuel price. Nick Miller, Advice on the costs of primary frequency regulation, 20 March 2018. Nick Miller has worked for many decades with GE Energy, most recently as Senior Technical Director Energy Consulting and was project lead for the AEMO report on Technology capabilities for fast frequency response, published March 2017. Mr Miller has previously provided technical advice to the Finkel review and the US Department of Energy and North American Electric Reliability Corporation (NERC).

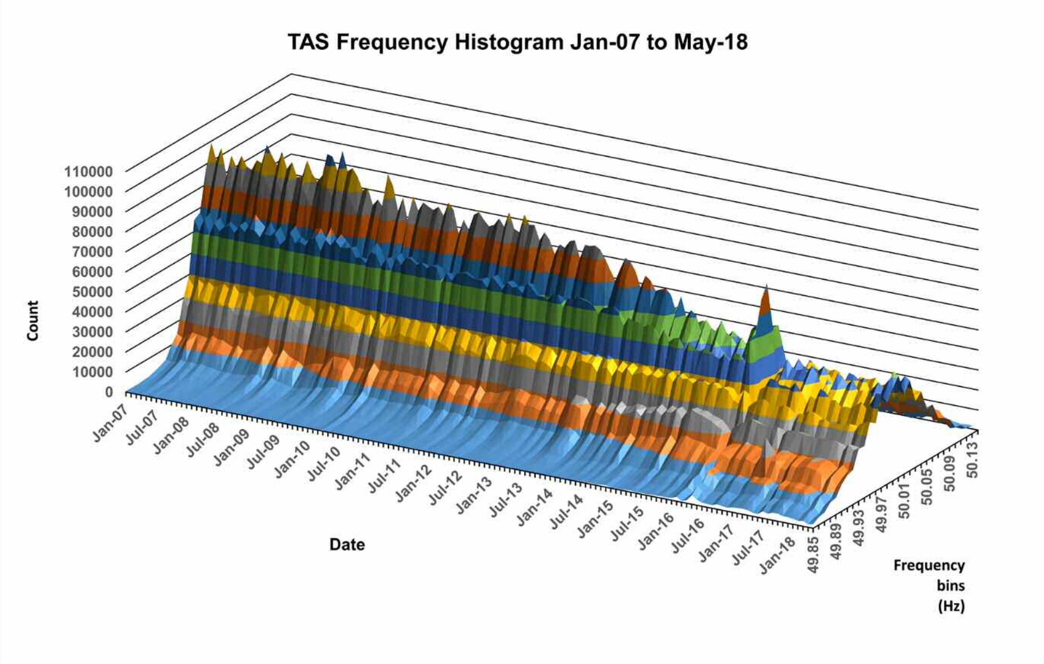
AEMC with a preliminary summary of the Tasmanian frequency control trials, which is provided below in Box 1.

BOX 1: NOTES ON AEMO'S FREQUENCY CONTROL TRIAL IN TASMANIA

Summary

The quality of frequency control in the Tasmanian power system under normal operating conditions has declined over the last several years, as shown in Figure A.2.

Figure A.2: Long term frequency performance in the Tasmanian power system



Source: AEMO

During May 2018, AEMO, in conjunction with Hydro Tasmania and TasNetworks, ran a series of frequency control trials in Tasmania. These trials involved changes to governor settings on Hydro Tasmania generating units, and to AEMO's AGC system. The effect on frequency control in the Tasmanian power system under normal operating conditions was assessed, as was the effect on the operation of Hydro Tasmania generating units.

These tests demonstrated that narrowing the governor frequency dead-bands on selected Hydro TAS generating units resulted in a significant and immediate improvement in the control of frequency in Tasmania under normal operating conditions. The role of AGC settings was found to be less significant on system frequency performance, at least under the test conditions used.

AEMO believe there would be value in conducting similar frequency trials on the mainland.

Test arrangements

During May 2018 the Basslink HVDC interconnector was out of service, removing a key influence on frequency in Tasmania. Hydro Tasmania governor settings and AEMO's AGC system are the other two key factors affecting frequency under normal operating conditions, and these two factors were selectively adjusted for periods of several hours at a time during these tests. Tests were conducted during the period 11:00 - 15:00, when there is minimal change in underlying Tasmanian demand.

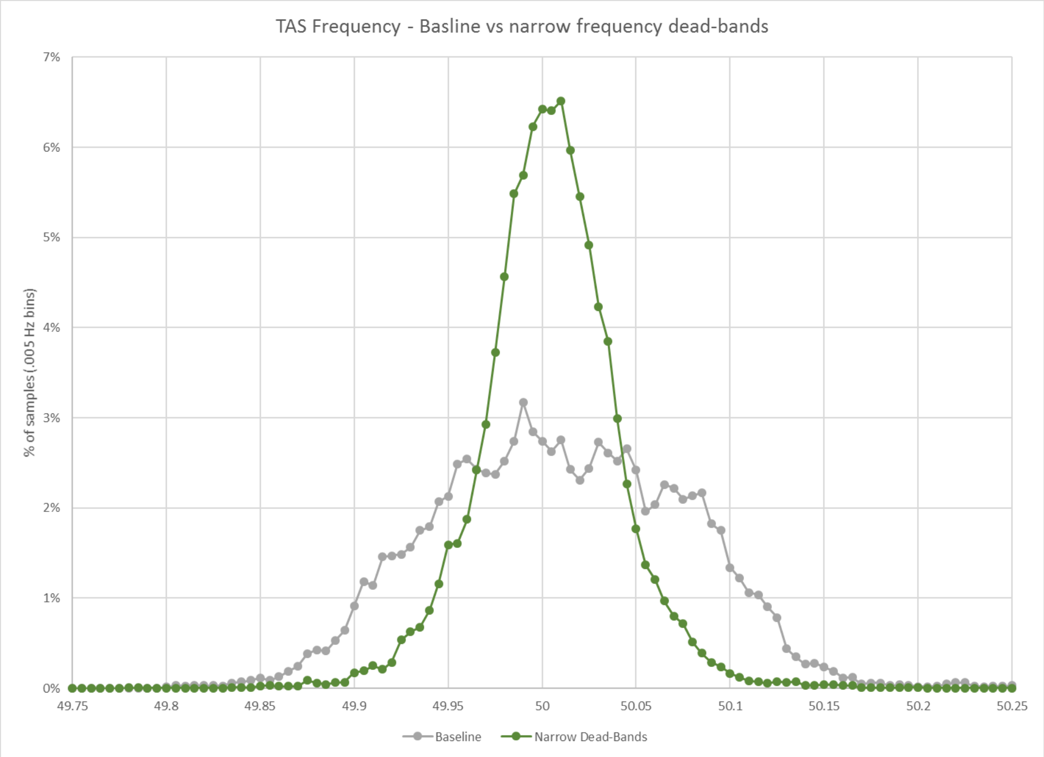
A number of different 4 hour test periods were used, with each test period involving a single selected change to either AGC or generator governor settings. During the tests data was recorded on system frequency, and on governor activity from selected machines.

All test periods were excluded from calculation of causer-pays factors, and from assessment of generator non-compliance. There was no intervention in energy or FCAS markets, or in dispatch during the tests. At the end of testing, all governor and AGC settings were restored to their pre-test values.

Effect of governor frequency dead-bands on system frequency

Figure A.3 compares a pre-test baseline period, with a period where the frequency dead-bands of selected Hydro Tasmania generating units were set to zero. These particular units normally operate with frequency dead-bands of +/- 80 mHz (i.e. within the NOFB, but a relatively wide dead-band). These changes were applied remotely, while the units were online. These tests demonstrated the key role of governor dead-bands on system frequency performance. As shown in Figure A.3, narrowing the dead-bands of these units resulted in the frequency being held far more tightly around 50 Hz.

Figure A.3: Tasmanian frequency control trial results - zero dead bands vs baseline

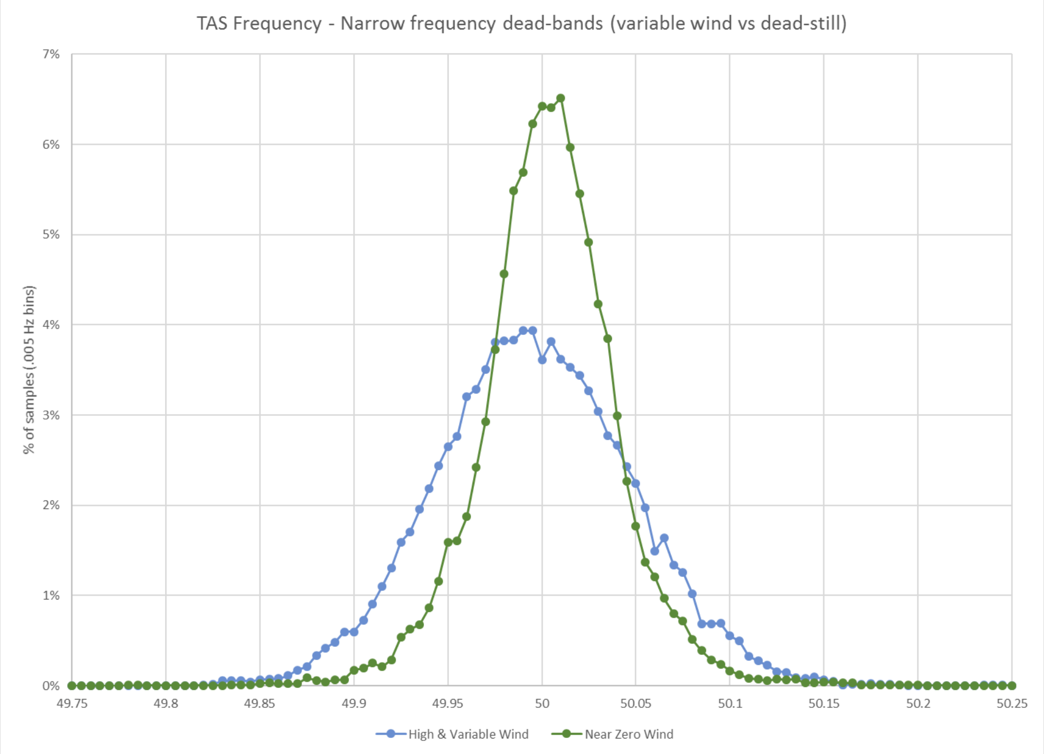


Source: AEMO

Effect of wind generation on system frequency

Figure A.4 shows two separate periods where the dead-bands of selected Hydro Tasmania generating units were set to zero. During one period there was near zero output from Tasmanian wind generation, during the other, there was relatively high, and variable output. This indicates that variability of wind generation plays a role in the frequency performance of Tasmania under normal operating conditions.

Figure A.4: Tasmanian frequency control trial results - zero dead bands vs zero dead band with high and variable wind output



Source: AEMO

Effect of tests on governor activity

Governor activity was assessed during these tests, to assess the impact on the operation of generation. This included assessing changes in guide vane movements on hydro units, and on deviation of generation from baseline MW targets.

Initial analysis of these results indicates that improved system frequency performance was associated with increased guide vane activity, and increased deviations from base MW targets.

Effect of AGC changes

During these tests AEMO trialled several changes to AGC. These included simple suspension of AGC functionality for frequency regulation, the use of dynamically calculated frequency bias, vs the current fixed frequency bias settings, and the use of permissive blocking, which limits AGC control of generation which would exacerbate a frequency deviation.

These tests provided limited information on the effect of AGC arrangements on Tasmanian system frequency performance. They did provide insight into potential AGC tuning changes that are likely to be of value in future. The test periods, which were associated with stable system conditions, and minimal change in underlying system load, were not generally challenging for AGC performance.

Future work - Mainland frequency trials

The mainland has seen a similar decline in the quality of frequency control over the last several years. The mainland power system is significantly different to that of Tasmania, both in terms of the size and the generation mix. The Tasmanian power system incorporates almost 3GW of generation capacity, of which approximately 80 per cent is hydro power, supported by small amounts of wind and gas generation. By contrast the mainland power system incorporates 48GW of generation comprising a mix of coal, gas, hydro, wind and solar power. As such, AEMO believes there would be value in running similar frequency tests on the mainland to provide a high degree of confidence in the findings. Such tests would allow direct assessment of the effect of changes in the volumes of primary frequency control on system frequency performance. It would also allow generation operators to assess impacts on the operation of their plant, and would provide an opportunity to trial AGC tuning changes.

Test periods of several weeks at a time are suggested, to capture load ramps, generation commitment and technology pattern changes, and variations in the output of renewable generation. Given the much larger number of participants, and the wide range of generation technologies involved, this would be a significantly more logistically complex exercise.

Subject to the results of the ongoing trials and investigations by AEMO, the Commission considers that the inclusion of an appropriately designed incentive mechanism to encourage primary regulating services is likely to lead to improved frequency performance during normal operation.

Limitations of the current arrangements for the cost recovery of regulating FCAS - causer pays

A principal objective of the regulating FCAS cost recovery arrangements is to place a financial incentive on market participants to act in a way that minimises the need to procure regulating services. By imposing the costs of the services on those market participants that give rise to the greatest need for the services, there is an incentive for those market participants to minimise adverse impacts to system frequency, and therefore minimise the overall requirements for the services. Such an arrangement should reduce the costs of regulating FCAS in the long term interests of consumers while achieving the objective of a secure power system.

The Commission is of the view that arrangements for financial incentives in relation to provision of frequency control services by market participants are likely to be efficient and effective where:

- transparent procedures allow participants to understand how their actions relate to the costs they are likely to incur

- there is an alignment of participants' impacts on system frequency and the costs they incur

The Commission has identified a number of issues with the current causer pays cost recovery arrangements for regulating FCAS which may be resulting in inefficient outcomes in terms of allocation of these costs

A temporal disconnect between a market participant's contribution to the need for regulating FCAS and the costs charged to that market participant

AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[73] Currently, AEMO has chosen to adopt a 28-day averaging period for the calculation of the contribution factors as outlined in AEMO's causer pays procedure.[74] Taken together with the notice period, this means that the allocation of regulation FCAS costs for a particular 28-day period is based on performance contribution factors determined over a four week period commencing around six weeks earlier.

The result of the 28-day averaging and misalignment of sample and application periods is that the volatility of regulation FCAS cost allocations is reduced. However the price signal for market participants to help to correct frequency deviations in any single dispatch interval is muted.

A lack of transparency and simplicity in the calculation of market participants' costs

When incentive arrangements are not transparent, or are not easily understood by market participants they may not be effective in guiding the intended behavioural outcomes.

AEMO's causer pays procedure outlines the approach used to calculate contribution factors and to allocate costs. However, a common complaint of the procedures has been that it does not provide sufficient details for participants to calculate their own contribution factors.

Charges for contributing to frequency deviations are not balanced through crediting or valuation of positive contribution factors

The current causer pays arrangements allocate the costs of regulating FCAS to each participant in proportion to the extent to which its deviations from a linear trajectory exacerbate movements in frequency. Helpful deviations are only rewarded to the extent that they offset harmful deviations within a market participant's portfolio of generating units and loads. This creates an incentive for generators to track their output as closely as possible to a linear trajectory to meet their dispatch target. This strategy has the effect of minimising harmful impacts on system frequency but also has the converse effect of minimising helpful contributions to system frequency.

A discussion of the valuation of positive contribution factors is included in Appendix B.

73 Clause 3.15.6A(na) of the NER.

74 AEMO, Regulation FCAS contribution factor procedure – DRAFT Version 6, April 2018, p.18.

AEMO has recently undertaken a review and consultation on the R*egulation FCAS contribution factor "Causer Pays" procedure* and published a draft report outlining a number of revisions to the causer pays procedure which go some way to addressing these issues.[75] These proposed amendments to the procedure include:

- a consolidation and clean-up of the procedure and improved explanation of key elements and themes
- an amendment to the procedure to ignore performance data for time periods where frequency indicator and frequency are mismatched[76]
- publication of frequency indicator data close to real time.

The Commission acknowledges that these changes represent an improvement to the transparency and ease of understanding of the causer pays procedure.

Considerations in relation to an incentive mechanism for primary regulating services

While frequency indicator may be an appropriate performance mechanism for measuring the need for regulating FCAS, the Commission are of the view that frequency measured in real time is likely to be a more appropriate measure of the need for a proportional primary frequency response.

The Commission also maintains the view that an efficient framework for encouraging primary regulating services is one in which there is an alignment of participants' impacts on system frequency and the costs they incur.

Section A.2 of this appendix sets out the Commission's approach to the development of a separate performance-based incentive mechanism to encourage the provision of primary regulating response.

The AGC system and regulating FCAS

As set out in the draft report, stakeholders have also expressed concern in relation to the effectiveness of AEMO's AGC system and the amount of regulating FCAS AEMO procures. AEMO is in the process of reviewing its approach to the determination of the required quantity of regulating FCAS and the settings for the AGC system that controls the provision of regulating FCAS.[77]

In section 5.3.1 of the draft report, the Commission noted that AEMO is currently investigating a range of potential improvements to the AGC including:

- updating the frequency bias setting used in the AGC calculations. 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
- review of the AGC regulation gain settings and low pass filter constants

75 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018.

76 Frequency indicator is a parameter used within AEMO's systems to indicate the extent to which more generation (in which case it is positive) or less generation (negative) is required to restore the frequency to 50 Hz. The sign of FI indicates which FCAS (raise or lower) is required at any given time.

77 AEMO, submission to the draft report, 26 April 2018, p.7.

- improved coordination between mainland and Tasmania

With respect to the quantity of regulation FCAS routinely procured by AEMO, it is understood that, for a large proportion of the time, this is being fully utilised during the dispatch interval, which suggests that more regulating FCAS may be required to manage frequency deviations. In response to this, AEMO is in the process of investigating the potential to modify its approach to determining the static and dynamic values for regulating FCAS. This may include increasing the base amounts for regulating FCAS and/or the criteria for increasing the amount in response to changing system needs throughout the day.[78] As reflected in the joint work plan, AEMO expects that this work will likely be undertaken in late 2018.

A.1.3 Frequency control during contingency events and coordination with other system services

There are also a number of drivers of change in the current market environment that, at some point, may limit the ability of the existing FCAS market arrangements to continue to deliver efficient market outcomes in the interests of consumers.

The AEMC concluded in the draft report that the current frequency control frameworks:

- 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
- reflect a 'traditional' generation mix and therefore may not adequately support new technologies and the services needed as the power system changes
- may not provide longer-term investment certainty due to a lack of counterparties willing to hedge FCAS market risks
- do not provide incentives for market participants to reduce their potential impact on the need for frequency control services.

These issues are set out in more detail below.

Lack of ability to value inertia and FFR, and coordinate with other system services

The existing FCAS markets were designed to reflect the inherent technical characteristics of the 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 value it separately from the provision of energy or FCAS.

However, in future, these assumptions will not necessarily hold. While high inertia steam turbines, hydro and combined cycle gas turbines currently represent over 80 per cent of the current installed capacity in the NEM, a significant share of this capacity will be retired over coming decades. Much of the new capacity being connected is non-synchronous. As

78 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. The amount of regulating FCAS for Tasmania is set at a static value of 50MW for both the raise and lower service.

this occurs, inertia may not be provided as a matter of course, and rates of change of frequency (RoCoF) following a system disturbance are likely to increase.

The value of inertia and FFR is therefore likely to increase over time. In the draft report the AEMC concluded that these services should be transparently valued so that investment decisions in new generation and storage assets reflect the value to the NEM of these and any other desirable characteristics. We noted that the level of inertia required to maintain RoCoF within a given limit can be divided into two components:

1. A **minimum level of inertia** required to maintain an islanded system in a satisfactory operating state. The *Managing the rate of change of power system frequency* rule made by the AEMC in September 2017 requires TNSPs to procure minimum levels of inertia (or other services that reduce the minimum level of inertia required).
2. **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. A market mechanism for inertia could improve reliability and lower overall energy costs by alleviating constraints on the system.

New technologies are capable of providing a frequency response that is much faster than traditional providers. In the draft report we concluded that 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 FCAS and inertia. We also concluded 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.

Limitations of current service definitions

The NER currently requires there to be six contingency services (the fast, slow and delayed raise and lower services) and two regulation services (raise and lower). The detailed specification of these services is set out by AEMO in the market ancillary services specification (MASS), which defines:

- the fast services as six second services
- the slow services as 60 second services
- the delayed services as five minute services.

These time frames reflect the response characteristics of the technologies in the system at the time the FCAS markets were established – i.e. steam, hydro and gas units. However, they may now restrict the participation of the new technologies being connected.

Further, participants in FCAS markets are paid for enabling the service in any dispatch interval in which they receive an enablement instruction. The volume of service available from a participant is calculated based on the energy estimated to be able to be injected over the measurement timeframe. These pricing structures have proven effective to date in optimising the provision of contingency services from conventional generating sources, but may not adequately reflect the value associated with the specific capabilities of new technologies.

In the long run, continued reliance on historically-determined service definitions and pricing structures 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.

Lack of contracting to support investment certainty

The current FCAS frameworks parallel the wholesale energy market in that participant bids are ranked in order of price, and all participants are paid the marginal provider's offer. In a workably competitive market, this approach enables the efficient dispatch of FCAS sources in real time. Historically, FCAS market participants have tended to provide FCAS as a by-product of energy generation. As such, potential revenue from FCAS market participation was unlikely to have been a significant factor in justifying the initial investment for the majority of the incumbent generators.

As conventional generators retire and newer technologies take their place, there is likely to be a greater focus on potential FCAS income. However, the existing market framework does not readily facilitate secondary contracting of the kind used by wholesale electricity market participants to create revenue certainty and underwrite investments. This may be due to the fact that FCAS costs are generally smeared across multiple market participants, or that FCAS costs have historically been low relative to the size of the energy market.

As noted above, newer technologies are capable of providing FFR, which may be more valuable as inertia levels decline, but may face limited revenue certainty under the arrangements described above. Under the *Managing the rate of change of power system frequency* rule made by the Commission in September 2017, TNSPs may enter into contractual arrangements with providers of FFR as a means of meeting their obligation to maintain minimum levels of inertia. These contractual arrangements are likely to provide some level of revenue certainty to those providers, albeit limited to the minimum level of inertia that is required.

Lack of incentives to reduce the requirement for frequency control services

Currently, AEMO determines the level of contingency FCAS to procure based on the impact of the single largest credible contingency event. The costs associated with sourcing contingency FCAS are recovered in proportion to market participants' energy consumption or generation. 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, it is possible that a single generator (or transmission element) could be a credible contingency event that is substantially larger than the next largest potential credible contingency. This means AEMO has 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, but the party setting the FCAS requirement pays the same in $/MWh terms as all other market participants.

As such, the current arrangements do not incentivise market participants to reduce their potential impact on the need for frequency control services. This undermines any price signals that might affect investment or operational decisions to minimise the need for contingency FCAS.

Many newer types of generating technologies have much smaller installed capacity. 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 require AEMO to procure large volumes of contingency FCAS to cater for a small number of potential contingency events.

A.1.4 Time frames for broader changes to frequency control frameworks

As the nature of electricity supply and demand in the NEM continues to change, there will be a need to re-evaluate the design of the existing frequency control frameworks. While the design of the existing regulating and contingency FCAS markets has proved effective in optimising the efficient dispatch of FCAS sources in real time, new approaches are likely to be needed over time to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies in a way that delivers efficient outcomes for consumers.

Incorporation of inertia and FFR

The initial instances of insufficient inertia in the NEM will likely arise from a separation contingency event that results in an area of the transmission network becoming islanded.

Since October 2016 AEMO has limited power flows on the Heywood interconnector between Victoria and South Australia to cap the size of the RoCoF that would occur should the interconnector fail. Since May 2017 AEMO has been applying additional constraints in South Australia that require a minimum level of synchronous generation to remain online at all times to address issues of low system strength. The additional inertia provided by these generating units has meant that the constraint on 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.

Market benefits may be achieved by additional synchronous capability to alleviate the system strength constraint instead of 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 and AEMO are in agreement that it would be difficult to derive a marginal price for bringing this additional capability online.

Two rule changes made by the AEMC in September 2017 require AEMO to determine minimum levels of inertia and system strength. The minimum required levels of inertia that AEMO sets (when they are known) will determine whether there is a residual market benefit to be obtained from the provision of additional inertia. Further, equipment that provides inertia, such as synchronous generating units and synchronous condensers, also provides system strength. Depending on 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.

To date, the focus on inertia has been in 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.[79] However, as the generation mix changes the requirements for inertia will also change. Inertia is likely to become more valuable in future and therefore the development of a market mechanism for additional inertia will likely be needed to provide price signals that promote efficient investment and economic benefits to consumers.

Analysis undertaken by AEMO indicates that, over the period 2011/12 to 2015/16, they observed a maximum RoCoF of 0.2 to 0.3 Hz/s up 17 per cent of the time. This is expected 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 a small proportion of the time. RoCoF exceeding 0.5 Hz/s are not expected to be significant for credible contingencies until sometime in the 2030s.[80]

AEMO's analysis suggests that contingency FCAS framework issues will intensify over the 2020s and as such it is important to continue to develop potential options to ensure frameworks are well positioned to support good frequency control into the future. Initial thoughts on such options are developed later in this appendix.

Integration of new frequency response technologies

In a paper published in August 2017, AEMO set out its views on when it expects FFR will become valuable in the NEM based on anticipated power system needs. It noted that:

- 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
- contingency FFR and primary frequency control show promise in the near term
- fast response regulation services may become important in future, and are technically feasible at present
- simulated inertia and grid-forming technologies are not yet commercially demonstrated, and have not yet been proven as a complete replacement for synchronous inertia.[81]

AEMO has indicated an intention to conduct trials and proof of concept projects, including with ARENA, to build confidence in the capability of FFR to deliver the frequency control

79 AEMO was required to determine the minimum required levels of inertia and system strength by 30 June 2018.

80 This analysis was undertaken before the AEMC made the Managing the rate of change of power system frequency rule. It is therefore unclear the extent to which the minimum inertia obligation on transmission network service providers would affect the outcomes of the analysis.

81 This conclusion was disputed by some stakeholders, who noted that there exist a number of demonstrated micro-grid projects with inverters operating in grid forming mode that maintain a simulated grid voltage and frequency.

services needed in the NEM. There are also a number of examples of new technologies and approaches being integrated and trialled in the NEM, including:

- EnerNOC, which is participating in the six second, 60 second and five minute contingency raise markets using aggregated demand response
- the Hornsdale Power Reserve, which is participating in all eight FCAS markets
- an in-market technical demonstration of FCAS provision by the Hornsdale wind farm, during which it successfully provided the 60 second and five minute contingency services and the two regulation services
- a trial at the Musselroe wind farm, which will further assess the ability of wind farms to participate in all eight FCAS markets.

In submissions to the draft report, many 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. If current synchronous generators return to providing primary frequency response and sustained inertia, this will modify the amount of FFR required.

A.2 Addressing the deficiencies in 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 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.

As the power system continues to change, 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 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 draft report therefore set out the AEMC’s views on the priority with which the identified issues should be addressed. Based on stakeholder feedback to the draft report, this final report moves away from categorising the issues as ‘immediate priorities’ and ‘emerging needs’, and instead sets out an ongoing program of work for the AEMC and AEMO to undertake alongside interested stakeholders to address the identified issues before or as they emerge.

- Section A.2.1 discusses the timeframes for addressing the recent deterioration in frequency performance under normal operating conditions and sets out the range of actions that AEMO is undertaking in the short term.
- Section A.2.2 explores the need for a longer-term solution for the provision of primary frequency control in the normal operating frequency band and sets out the criteria that should be used to design an appropriate mechanism.
- Section A.2.3 describes a dynamic performance based deviation pricing mechanism that could be implemented to value primary regulating response over the long term.
- Section A.2.4 outlines illustrative alternative frameworks developed by the Group of generators and IES and presented in submissions to the draft report.
- Sections A.2.5 and A.2.6 discuss how a deviation pricing mechanism might interact with regulating FCAS and how it might be extended to value contingency FCAS and inertia.

A.2.1 Addressing the deterioration of frequency performance in the short term

The current frequency control frameworks do not require or incentivise market participants to provide a primary regulating response to support good frequency control under normal operation.

The draft report recommended two options to incentivise and reward the provision of a primary regulating response for further work and investigation:

1. The provision of a primary regulating response through the existing regulating FCAS markets.
2. Changes to the procedure by which AEMO recovers regulating FCAS costs (known as the ‘causer pays procedure’) to facilitate the provision of incentive payments for primary regulating response.[82]

The draft report also considered these options in the context of broader, longer-term changes to the existing FCAS market frameworks to appropriately value and incentivise the provision of frequency services as the power system changes.

Submissions to the draft report indicated that many stakeholders did not support the first option above because:

- such an approach would be unlikely to deliver suitable levels, or a sufficient distribution, of primary regulating response
- some participants may be unable to provide regulating FCAS and a primary regulating response, which would reduce the competitiveness of the market for regulating FCAS.

Of the two, stakeholders largely preferred the second option as an interim approach to addressing the deterioration while developing a more long-term solution.[83] The following sections set out the Commission’s initial considerations on the development of a flexible long-term mechanism to incentivise primary regulating response in the NEM.

82 The report also identified broader issues with this procedure and made some recommendations on how it could be improved.
83 A discussion of stakeholder views on the other options presented in the report is set out in [Appendix B].

In its submission to the draft report, AEMO was of the view that "while a form of payment mechanism would be the most effective solution for the procurement of primary frequency control in the longer-term, the design of any mechanism must build on the underlying technical needs of the system." AEMO explained its intention to conduct a range of actions by the end of 2018 to help it better understand the engineering requirements necessary to achieve effective frequency control. It therefore recommended that the AEMC consider the outcomes of those actions before putting in place any new regulatory or market arrangements to deliver a primary regulating response.

AEMO is undertaking a range of actions in an attempt to better understand the drivers of the deterioration of frequency performance under normal operating conditions, and to reverse this deterioration, or at the very least halt any further deterioration.

AEMO intends for these actions to be materially complete by the end of 2018. Specifically, AEMO is intending to:

- conduct a survey of generator frequency control settings (completed April 2018)
- conduct a trial of primary frequency control in Tasmania (completed May 2018)
- publish a revised causer pays procedure to provide greater clarity and transparency and remove aspects that may be discouraging the provision of a primary regulating response
- conduct AGC tuning (late 2018)
- investigate the need to increase the quantity of regulating FCAS on a static or dynamic basis, and doing so if necessary
- conduct a trial of primary frequency control in the mainland, building on experience from the Tasmanian trial undertaken in May 2018
- monitor and report quarterly on frequency outcomes, on a voluntary basis
- continue coordination of proposed changes to generator governor settings following the results of the survey conducted in April 2018.

AEMO advises that there is no immediate need to implement regulatory change to address the deterioration before the results of these short term actions are known, and that current regulatory tools are expected to be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard within this timeframe.

This report therefore does not recommend any regulatory change to address the deterioration in the immediate term. Rather, it sets out a work plan that assumes AEMO will undertake the actions it has proposed and that it is appropriate for the AEMC, AEMO and other stakeholders to understand the impact of these actions before considering any regulatory change.

The work plan includes that AEMO will assess the effectiveness of its short-term actions at meeting the requirements of the frequency operating standard, and whether there is a need for an interim measure to be put in place before a longer term mechanism for the procurement of a primary regulating response comes into effect. Notwithstanding practical viability, potential interim measures may include:

- those that might not require regulatory change (e.g. AEMO negotiating with generators, or issuing directions)
- those that would likely require regulatory change (e.g. mandatory provision of primary frequency control, a new contracting arrangement or valuing positive contribution factors through the causer pays procedure).

AEMO will monitor and report on frequency performance outcomes with respect to the requirements of the frequency operating standard on an ongoing basis.

Specification of the frequency performance during normal operation

As described in section 2.1, the NER set out the high level requirements for how frequency is managed in the NEM. This includes the maintenance of a satisfactory operating state and the operation of the power system in compliance with the frequency operating standard.[84] Through the course of this review, the Commission considers that it may be necessary to review certain structural elements of the frequency operating standard, particularly in relation to how the frequency performance of the power system is specified during normal operation.

As noted in section A.1.1 and shown in Figure A.1, the frequency distribution in the NEM during normal operation has flattened significantly in recent times. So far, excluding contingency events, the mainland frequency has been maintained within the normal operating frequency band for at least 99 per cent of the time consistent with the frequency operating standard. However, this requirement was not met in Tasmania from February 2016 to February 2018, with the exception of August and September 2016.[85]

The proposed responses to the recent degradation of frequency performance during normal operation that are set out in this report comprise potential changes to the existing tools that AEMO uses to manage frequency in the NEM (regulating services and the causer pays procedure) as well as the development of new tools, such as a mechanism to incentivise primary regulating response. However, noting that the current frequency degradation during normal operation is largely compliant with the NER and the frequency operating standard, the Commission recognises that it may be appropriate to review how the performance target for system frequency during normal operation is specified.

For example, as noted in the AEMO advice to this review, the current requirement in the NER and the frequency operating standard is that the frequency be maintained within the normal operating frequency band for 99 per cent of the time and returned to this band within certain timeframes following an excursion outside it. The current arrangements do not specify the required frequency performance <u>within</u> the normal operating frequency band and there is no requirement or principle for AEMO to attempt to return the frequency to the mid-point of the normal operating frequency band or 50Hz.

84 Clause 4.2.2(a) of the NER defines the power system as being in a satisfactory operating state when, among other things, “the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band.”

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

Therefore, the Commission proposes to consider how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard. This will include consideration of whether the NER or the frequency operating standard should prescribe in more detail the required frequency performance within the normal operating frequency band.

A.2.2 Longer term changes to frequency control frameworks

While AEMO's actions may address the immediate deterioration of frequency performance under normal operation, they neither incentivise nor require the provision of a primary regulating response. As such, the AEMC is of the view that there is a need to find a more permanent solution to the issue.

Furthermore, the AEMC has examined the broader structure of the existing FCAS markets to determine:

- whether they will remain fit for purpose in the longer term
- how to most appropriately incorporate FFR services, or enhance incentives for FFR services within the existing markets
- longer-term options to facilitate co-optimisation of energy, FCAS and inertia.

As the nature of electricity supply and demand in the NEM continues to change, there will be a need to re-evaluate the design of the existing frequency control frameworks. While the design of the existing regulating and contingency FCAS markets has proved effective in optimising the efficient dispatch of FCAS sources in real time, new approaches are likely to be needed to maintain the effectiveness of the existing available resources and to enable participation by emerging technologies in a way that delivers efficient outcomes for consumers.

While the timeframe over which new services are likely to be required is uncertain, it does appear to be sufficiently long to allow for the implementation and understanding of the impact of any solutions to address the deterioration of frequency performance in the normal operating frequency band prior to making any more substantial changes to address the deficiencies of the existing contingency FCAS markets and the lack of incentives for inertia and FFR.

As part of the work plan, the AEMC intends to commence a detailed exploration of the range of market/incentive based approaches to the provision of primary frequency control (and potentially other frequency services) for the longer-term, informed by approaches in international power systems. In consultation with AEMO and stakeholders, the AEMC will determine the most efficient approach and avenues to its development and implementation.

This section explores the need for a longer-term solution for the provision of primary frequency control in the normal operating frequency band and sets out the criteria that should be used to design an appropriate mechanism.

A discussion is also provided of the need to re-evaluate the design of existing frequency control frameworks for regulating and contingency FCAS and the extent to which a longer term solution for primary frequency control could be extended to achieve this outcome.

Spectrum of potential FCAS frameworks

Any changes to the FCAS frameworks will involve trade-offs. Enhanced frequency control, delivered through a greater volume of ancillary services or stricter requirements on market participants, will likely impose additional costs that are passed onto consumers. It is also 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:

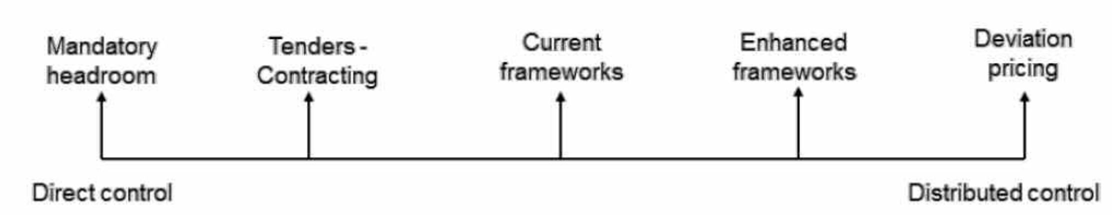
1. market-based mechanisms
2. intervention or regulatory mechanisms.

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, more distributed control over the provision of services can achieve economically superior outcomes, but may reduce levels of confidence where security concerns are manifesting in operational time scales or where the risk external to the energy market prevents it from being well-functioning.

The existing frequency control framework, 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 draft report set out a spectrum of alternative frameworks for the procurement and dispatch of FCAS, reflecting various levels of control from centralised to distributed, and discussed the relative advantages and disadvantages of each. This spectrum represents a trade-off between higher levels of certainty and confidence in the maintenance of system security and increased efficiency and flexibility in the provision of services.

Figure A.5: 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 (via the 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 far right end of the spectrum 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 method by which the price is determined, market participants are free to make decisions around the level of frequency response that they wish to provide.

Each of the options on the spectrum were designed operate in parallel with, or be integrated as part of, the existing NEM design. That said, we acknowledge that any wholesale review of FCAS frameworks needs to be considered in the context of broader changes to market design, such as the introduction of ahead markets.

Meeting the future needs of the power system through changes to FCAS frameworks

The relevance of adjusting the existing FCAS frameworks towards either direction on the spectrum above can be informed by the extent to which the future requirements of the power system are met by any such change. That is, whether the approach:

- reduces barriers to the participation of emerging technologies and efficiently values service provision
- enables the co-optimisation of the provision of frequency control services with inertia
- coordinates the locational requirements of frequency control services and other system security constraints, such as system strength
- reduces the potential variability and unpredictability of supply demand imbalances.

In the draft report, the AEMC concluded that the FCAS frameworks on the right side of the spectrum set out above are better able to meet these needs because:

- they 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
- 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
- they are generally technology neutral
- there is flexibility to vary the required frequency response over time to adapt to changing market conditions

- the potential lack of investment certainty may be ameliorated by the ability for market participants to enter into bilateral contracts
- they are likely to be better able to enable the co-optimisation of frequency control services with inertia and system strength as they have a higher degree of flexibility to dynamically adjust the mix of services required in real time than those on the left side of the spectrum
- they provide market participants with a direct real time incentive to minimise their impact on the need for frequency control services.

While there were few detailed comments on this aspect of the draft report, there was general agreement among stakeholders that any future frequency control frameworks should be non-mandatory and market-based. These views were reconfirmed at the technical working group meeting that was held on 22 May 2018, with a number of stakeholders also seeking further detail on timeframes for developing and implementing any long term changes to FCAS frameworks.

RECOMMENDATION 1: ARRANGEMENTS FOR THE PROVISION OF PRIMARY REGULATING SERVICES

In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

In order to develop such a mechanism, the Commission supports AEMO's trialling of changes to generator governor settings in Tasmania and the mainland, and associated technical investigations by AEMO, which are expected to be complete by December 2018.

The Commission recommends that the results of these trials and investigations be used to develop an explicit mechanism to incentivise the provision of a sufficient quantity of primary regulating services to support good frequency performance during normal operation. This will be important to securing sufficient volume of this service in the future for the evolving power system.

A.2.3 A dynamic performance-based pricing approach

In order to support the provision of an increase in primary frequency control, it must be demonstrated that the costs to providers are likely to be lower than the benefits arising from an improvement in frequency performance.

As such, the efficient and effective achievement of good frequency performance is most likely to occur in circumstances where participants are rewarded or penalised consistent with the value of their actions on system frequency. Costs should be imposed on those participants that contribute to frequency deviations. This would create an incentive to minimise adverse impacts to system frequency. At the same time, payments should be made to those participants that contribute to minimising frequency deviations. This would create an incentive for these market participants to assist with the support of system frequency.

The following assessment criteria are suggested as a good basis for guiding the development of an efficient and effective policy mechanism:

- **Performance-based and dynamic** - Payments made to participants to support frequency, and charges to participants that contribute to frequency deviations, must be consistent with their actions and the value these actions provide to the system.
- **Transparent** – Participants must be provided with the means of understanding how their actions relate to the costs or rewards they are likely to incur.

The remainder of this section provides a more detailed explanation of one possible policy mechanism, referred to as a deviation pricing mechanism, which could be developed to efficiently value the provision of a primary regulating response. The design of this mechanism is guided by the two principal criteria set out above and is consistent with the right hand side of the spectrum reflecting increased efficiency and flexibility in the provision of services.

The Commission suggests that a deviation pricing mechanism may be superior as a means of incentivising the provision of primary regulating response within the normal operating band for the following reasons:

- *It increases levels of participation and values responses from a range of technologies*

Primary frequency control action requires that a significant proportion of the generation fleet is enabled at all times for the continuous provision of the service. AEMO's modelling suggests that greater than approximately 30% of the online fleet should be actively providing primary frequency control at any given point in time for an effective primary response characteristic.

The deviation pricing mechanism does not require the development of a pre-specified profile of response but rather rewards and penalises participants' impacts on frequency in proportion to their actions and the value they provide to the system. This allows frequency providers to tailor their actions to the costs of providing a response and allows the response from a greater range of technologies to be valued, thereby maximising levels of participation.

- *It increases transparency and investment certainty*

A deviation pricing mechanism consists of a transparent system of rewards and penalties that allows participants to easily understand how their actions relate to the costs they are likely to incur. This would likely increase investment certainty for participants and thereby lower the overall long term costs of frequency control.

The proposed deviation pricing mechanism could initially operate as an incentive for a primary regulating response within the normal operating frequency band noting that it is possible the mechanism could also be extended to value contingency FCAS, FFR and inertia.

The Commission acknowledges that a deviation pricing mechanism is but one means by which a primary regulating response could be valued. There are alternative arrangements for the provision of a primary regulating response that sit on the spectrum of potential FCAS frameworks described in the previous section.

In response to the draft report, a number of submissions were received outlining relatively detailed alternative frequency control frameworks. In particular:

- The Group of Generators outlined an alternative framework lying roughly midway on our control spectrum described above.[86] This was based on central procurement of volumes of services supported by performance based cost recovery.
- Intelligent energy systems (IES) outlined a suite of changes that would move the framework substantially towards the distributed control end of the spectrum.[87]

These approaches reflect alternatives to the deviation pricing mechanism outlined below that also seek to capture our identified criteria with respect to being performance based and dynamic as well as transparent. These proposals are described further in section 2.4.

Performance-based and dynamic

The deviation pricing mechanism 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 structure.

The mechanism operates on the basis of a symmetric payment and cost recovery incentive framework. 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 frequency deviations away from 50 Hz. The net result is a balanced two-way system of payments and charges that provides an incentive for market participants to control their generation or load in a manner that supports system frequency.

A key feature of a deviation pricing mechanism is that it allows all frequency control technologies to be appropriately valued in accordance with the speed and profile of their response. The amount that is either paid by or charged to participants is proportional to the value of the response that they provide or the costs that they impose on the system respectively.

Method to determine the price

A key element of a deviation pricing mechanism is the method used to calculate the price that is either paid to participants that support frequency or charged to participants that contribute to frequency deviations. The price would need to be updated more frequently than once every dispatch interval in order to accurately reflect changes in participants' impacts on system frequency.

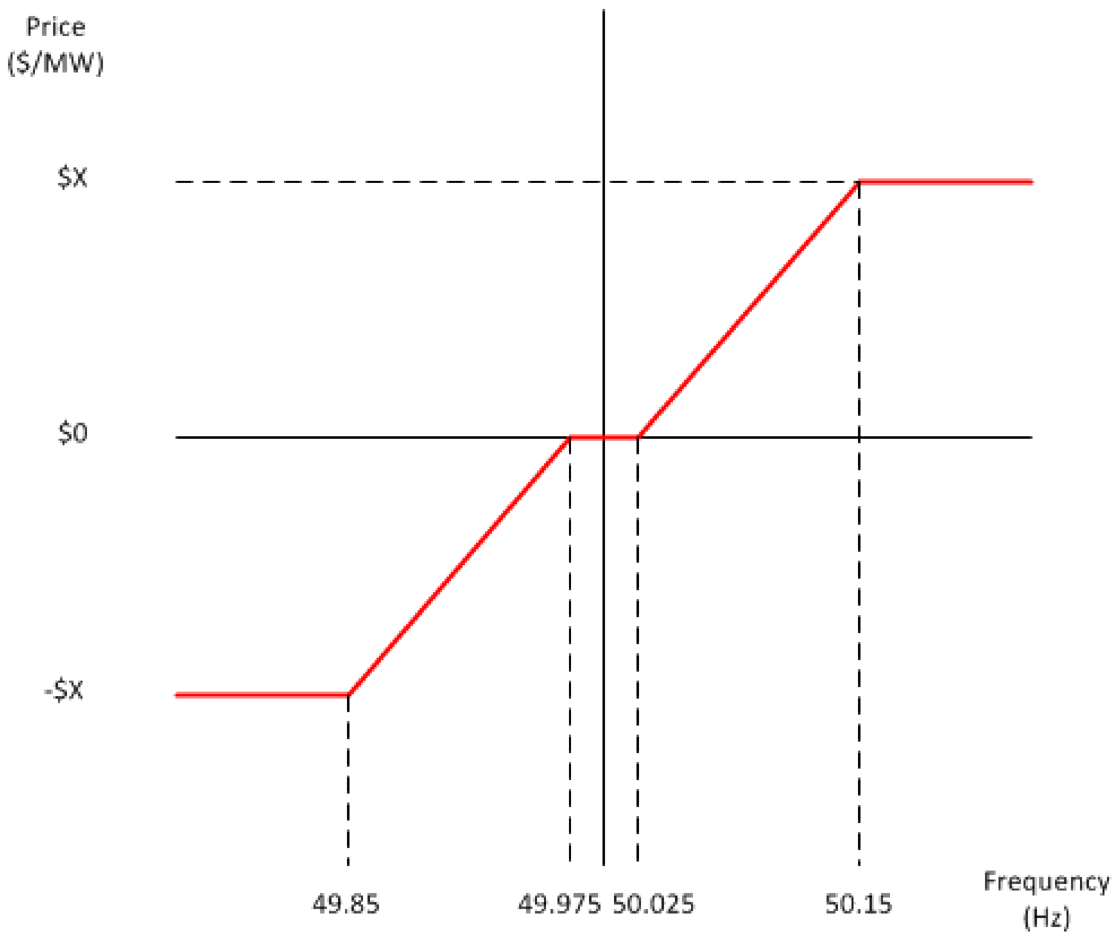
86 Generator Group, Submission on the draft report, 5 March 2018, pp. 71-77. The Generator Group is: Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity and Intergen. Consultant engaged to assist with the development of the proposal were SW Advisory and DIgSILENT.

87 Intelligent Energy Systems, Submission on the draft report, 25 April 2018.

One option for a method to calculate the price is through the use of a transparent symmetric price function with a rapidly increasing incentive (price) as frequency deviates further from the central target of 50 Hz. This standing price function would use system frequency as the primary variable and would thereby allow for the price to be updated continuously based on changes in system frequency.

An example of such a price function could be based on a linear price increase outside of an initial narrow frequency dead band centred on 50 Hz with the price increasing to (for example) the market price cap at the extremities of the normal operating frequency band as illustrated in Figure A.6. This price function could take any form with the illustrated form showing a simple linear relationship that reflects the increasing value of frequency control services as frequency moves further away from 50 Hz.

Figure A.6: Possible deviation price function



Note: This figure presents a possible hypothetical price function. Key elements of this price function are that it: (1) includes a frequency dead band of 0.025 Hz either side of 50 Hz where the price is $0/MWh reflecting the ongoing role of regulation FCAS to ensure frequency averages 50 Hz together with likely limits on measurement error and the desirability of frequency responsive generators not "hunting" around 50 Hz; (2) has a negative price for low frequency situations (frequency < 50 Hz) reflecting a design characteristic whereby frequency deviation is defined as the current frequency minus 50 Hz which gives a negative value where the frequency is below 50 Hz (and thereby ensures a positive payment to generators supporting good frequency control, i.e. at 49.9 Hz the frequency deviation would be -0.1 Hz which when multiplied by a negative price would ensure a positive payment; (3) plateaus at the edge of the normal operating frequency band (i.e. 49.85 Hz and 50.15 Hz), at which point contingency services are responsible for resolving any further frequency deviation.

Once the price function is determined, payments and charges to each participant can then be calculated based on the participant's actions with respect to system frequency. Participants with a generating output that has deviated from their linear dispatch trajectory would either receive or pay the price depending on whether their deviation supported or contributed to the frequency deviation. For example, a generating unit that reduced output below its dispatch trajectory while frequency was above 50 Hz would receive a payment.

The difference in MWs between a participant's output and its baseline trajectory would be multiplied by the price to determine the overall payment or charge. In this manner, the mechanism would create a financial incentive for participants to limit the extent to which they deviate from the linear trajectory of their dispatch targets, unless to do so supports the frequency of the power system.

Payments and charges to participants would at all times remain proportional to the participant's actions. If a participant changes the profile of its response then it would either receive or pay an amount that reflects the change in its actions.

Those participants that respond to smaller frequency deviations will be those that are able to do so at a lower cost, reflecting the value that this provides to the system. Increasingly higher cost generators will be incentivised to respond to larger frequency deviations where the need to support system frequency becomes more valuable. The transparent and pre-defined price function thereby leads to a more efficient outcome in real time by creating an effective merit order of frequency response in the system.

The deviations of non-scheduled participants would also be assessed against a baseline trajectory. As discussed above, AEMO forecasts the level of non-scheduled load or generation at the end of a dispatch interval and then dispatches scheduled load and generation to meet that forecast in aggregate. In principle, any non-scheduled participant should be able to provide its own five-minute forecasts to AEMO. These self-forecasts could then be used to calculate deviations by comparing the forecast against actual. Participants with good forecasting capabilities would be able to reduce their overall deviation charges as a result.

The AEMC has recently been considering the concept of demand-side forecasting through the *Reliability frameworks review*.[88] This report has recommended a number of improvements to NEM forecasting. Further details are provided in ppendix C. Demand-side

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

forecasting along with availability of 4 second metering would create the opportunity for all market participants to engage in any proposed deviation pricing arrangement and reduce the size of any residual associated with such arrangements.

BOX 2: CALIBRATING AND UPDATING THE PRICE FUNCTION

A key component of the deviation pricing mechanism is the price function that is used to set the price that participants are paid for supporting frequency or are charged for contributing to frequency deviations.

If the price function is set too low then there may be little improvement in frequency performance. Participants may decide to be relatively unresponsive to frequency changes and AEMO would rely to a greater extent on the use of regulating FCAS.

In theory, given a sufficient number of competing participants in the deviation pricing mechanism, there should be limited if any risk of an overly generous price function leading to excessive payments (assuming the price function starts at $0 and increases as frequency varies from 50 Hz). This is because excess returns would be competed away as additional participants respond to prices above their marginal cost of supply. Nevertheless, especially during the initial stages of a deviation pricing mechanism, limiting the magnitude of the price function may be desirable as any higher costs of frequency response will be passed through to consumers.

There are a number of means by which the price function could be calibrated to provide a target level of frequency response.

1. Adjust on the basis of historical FCAS prices – The price function could be determined on the basis of the required fair value of the deviation price consistent with achieving the historical FCAS prices observed for the eight separate FCAS markets. A line of best fit would be taken through the series of calculated fair value prices in order to arrive at a deviation price function that best approximates the overall value of frequency response.
2. Progressively increase the price function – The effect of introducing a deviation pricing mechanism would be to increase the level of autonomous primary frequency response in the system. It is possible that the price function could be set initially to provide a relatively weak price signal, and then incrementally increased over time until a target level of frequency performance is achieved. As the price signal becomes stronger, AEMO may determine that it needs to procure lower volumes of regulating FCAS. It is possible that, through this method, the need for regulating FCAS may reduce significantly or even be eliminated.
3. Base the price function on the marginal value of frequency performance – A small increase in helpful deviations from a participant will result in a small improvement in frequency performance. The marginal value of this improvement could be used to set the price function. There may be some challenges in estimating the marginal value of frequency response as it is likely to change depending on the extent of the deviation

> from 50 Hz. Small deviations may be more reflective of the impact to participants that respond to frequency changes. For larger deviations, the marginal value of frequency performance would be higher as the threat to system security increases.
>
> Given AEMO's principal role in maintaining system security, it follows that it should be responsible for updating and calibrating the price function. An alternative candidate is the Reliability Panel. However the Reliability Panel's role with respect to frequency performance is to maintain the Frequency Operating Standards. It is then AEMO's responsibility to make sure that these standards are met.
>
> The time intervals between updates to the price function would also need to be considered. It is likely that the price function would not need to be updated very often, as it is likely to be the cost structures of frequency responding technologies that influence the prices that need to be paid or charged. However, some form of periodic review will be necessary so that the price function remains reflective of the costs of the prevailing frequency response technologies in the market and the value to consumers.

A transparent framework

The deviation price function would be specified and published in advance. As frequency is readily observable in the power system, and each participant is aware in real time of the extent to which it is deviating from its linear baseline trajectory, this would allow market participants to determine their potential liability under the deviation price function in real time. In its submission on the draft report, CS Energy agreed that the price function should be published so as to inform operational decisions by market participants.[89]

With a transparent price function, participants will readily be able to determine the optimal profit maximising settings on their plant. Each participant will be able to calibrate the level of its frequency response based on the costs and capabilities of its respective generating plant. Indeed, some generating plant with more modern control systems may be able to develop control algorithms that optimise plant settings consistent with the pre-defined price function.

As each participant will be able to optimise their control settings, this will mean that those generators that are able to provide a frequency response at a lower cost will set their dead bands at a narrower range and will therefore be the first to respond to any deviations in frequency. Increasingly higher cost participants will set their dead bands at wider ranges so as to only provide a frequency response in the event that frequency deviations are larger and the payments or charges are higher.

Furthermore, the introduction of a dynamic performance-based mechanism would likely assist more unconventional frequency response technology developers to find a market for their products. For example, Fluence suggested that grid batteries are a higher quality source of primary frequency control and quoted figures from the PJM market which

89 CS Energy, Submission on the draft report, 24 April 2018, p. 10.

suggests that each MW of energy storage is equivalent to over 2 MW of traditional generation based on accuracy and performance.[90]

Additionally, an innovator developing a new frequency response technology, or a new control algorithm for a conventional technology, would be able to test the effectiveness and profitability of their products by using an off-line model of the deviation price function driven by historical or predicted prices.

Measuring frequency response

As with current causer pays arrangements, a deviation pricing mechanism would require relatively granular measurement of performance through four-second SCADA data. Any participant would be able to respond to deviation prices. The only requirement would be to have four-second metering capability.

Under a deviation pricing mechanism, this data would only be required for settlement purposes. Data metering would not be required in real time in order 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 mechanism.

Participants without fast metering

There is a potentially substantial portion of the market where four second or equivalent metering may not currently be feasible and where retrofitting such capability may never be economic, given the relatively low value of frequency response. Without four-second metering, it would not possible to transmit the deviation price signals that incentivise helpful, and discourage harmful, actions that impact on system frequency.

Currently, this portion of the market is predominantly made up of small and medium sized consumers. Under the causer pays arrangements, the residual costs of regulating FCAS are allocated to market customers as a whole. To the extent that an individual response provides value, this value is shared across the entire class, with the individual responder capturing only a very small part of this. It is likely that this system would be continued under the deviation pricing mechanism.

However, distributed energy resources may also face high relative costs of metering, and with a greater uptake of these technologies, there are likely to be instances where sudden frequency changes can occur from these technologies responding in aggregate to significant changes in the energy price from one dispatch interval to the next.

While it may not be practical to test and measure the provision of frequency response from each individual unit, there may be ways to do this on a more aggregated or sampled basis. As set out in Appendix D, the Commission considers that there is value in AEMO undertaking trials of distributed energy resources providing market ancillary services with a view to

90 Fluence, Submission on the draft report, 24 April 2018, p. 6.

assessing different methods for metering and verifying a response. 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 1 second resolution. It may also provide a means to test a certain proportion of an aggregator's portfolio and make assumptions about the remainder on that basis.

In its submission to the draft report, AEMO noted that it was seeking to trial aggregated distributed energy resources providing FCAS and suggested assessing how to balance the need to accurately assess service provision against the costs of specifications. One potential approach suggested by AEMO is the sampling across a set number of generating units with high speed monitoring and extrapolating that response across the remaining generating units with low speed metering.[91]

A.2.4 Submissions outlining detailed alternative frameworks

In response to the draft report, a number of submissions were received outlining relatively detailed alternative frequency control frameworks. In particular:

- The Group of Generators outlined an alternative framework lying roughly midway on our control spectrum described above.[92] This was based on central procurement of volumes of services supported by performance based cost recovery.
- Intelligent energy systems (IES) outlined a suite of changes that would move the framework substantially towards the distributed control end of the spectrum.[93]

These approaches reflect alternatives to the deviation pricing model outlined above that also seek to capture our identified criteria with respect to being performance based and dynamic as well as transparent. These approaches are briefly summarised below.

Group of Generators proposal

The Group of Generators submission suggested a number of changes to frequency control frameworks involving:

- A market-based solution to the provision of primary frequency control within the normal operating frequency band. This was based on the establishment of a new FCAS market for a primary regulating service that operates within the NOFB that is suggested to be more economically efficient than a mandatory requirement for frequency response via the NER technical standard. The group of generators report envisages additional markets for primary raise and lower FCAS operating alongside the existing secondary regulating raise and lower FCAS markets. This would involve procurement of a centrally determined volume of services similar to the current framework.
- An alternative market arrangement for procurement of contingency FCAS based on a continuous valuation of different response characteristics. The Group of Generators

91 AEMO, submission to draft report, p. 11.

92 Generator Group, Submission on the draft report, 5 March 2018, pp. 71-77. The Generator Group is: Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity and Intergen. Consultant engaged to assist with the development of the proposal were SW Advisory and DIgSILENT.

93 Intelligent Energy Systems, Submission on the draft report, 25 April 2018.

report envisages a reformation of the contingency FCAS markets away from the definition of discrete fast (6 sec), slow (60 sec) and delayed (5 minute) contingency services in favor of a single continuous contingency FCAS market where the dispatch of providers of contingency response would be via an automated co-optimisation process that took account of provider offers, system characteristics and the frequency operating standard in order to dispatch the optimal mix of contingency services.

In effect, the Group of Generators approach would, in the context of primary frequency response in the normal operating frequency band, create new additional, revenue streams that market participants could access should they so choose, while for contingency services, the proposal would simplify the number of markets in operation but would customize the payment to participants to reflect the individual characteristics of their response.

Intelligent Energy System's (IES) proposal

IES outlined a package of reforms to incentivise market participants to maintain system frequency for secure operation of the power system. The IES report focuses on three key areas for reform and proposes a number of 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 proposes a ramping energy price that 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)

- *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.
- *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

- *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.

- *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.

A.2.5 Interactions of a deviation pricing mechanism with regulating FCAS

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.[94] As such, it is likely that the procurement of regulating FCAS under the existing frameworks will need to continue, at least initially, with the introduction of a deviation pricing mechanism. However, in order to have the two mechanisms operating in parallel, there would need to be some means of avoiding double-payments to participants already being paid for the provision of regulating FCAS.

Under the current framework, a provider of regulating FCAS is obliged to have a specified response to AGC instructions when it is enabled. As it is paid for the enablement of this response, there is then no justification for paying them for the same contribution to support frequency under a deviation pricing mechanism. The existing causer pays arrangements avoid this double payment by not crediting regulating FCAS providers for helpful deviations.

One option would be to simply exclude regulating FCAS providers from receiving payments through the deviation pricing mechanism. However, in order to achieve an efficient outcome, regulating FCAS providers should be rewarded for helpful deviations which go beyond their AGC instructions. Conversely, they should also be penalised if they fail to meet the minimum requirements of the AGC instructions.

It is possible to achieve this outcome by requiring regulating FCAS providers to pass onto AEMO the deviation payments that they would have received if they performed exactly as instructed through the AGC system. This would be in the form of a ‘fair value’ payment equal to the amount that the regulating FCAS provider would earn if, instead of selling its response to AEMO as FCAS, it instead provided the same response autonomously and received payments through the deviation pricing mechanism. AEMO would receive fair value payments from regulating FCAS providers but would continue to pay them the FCAS enablement payments under the existing framework.

Calculation of the fair value payment

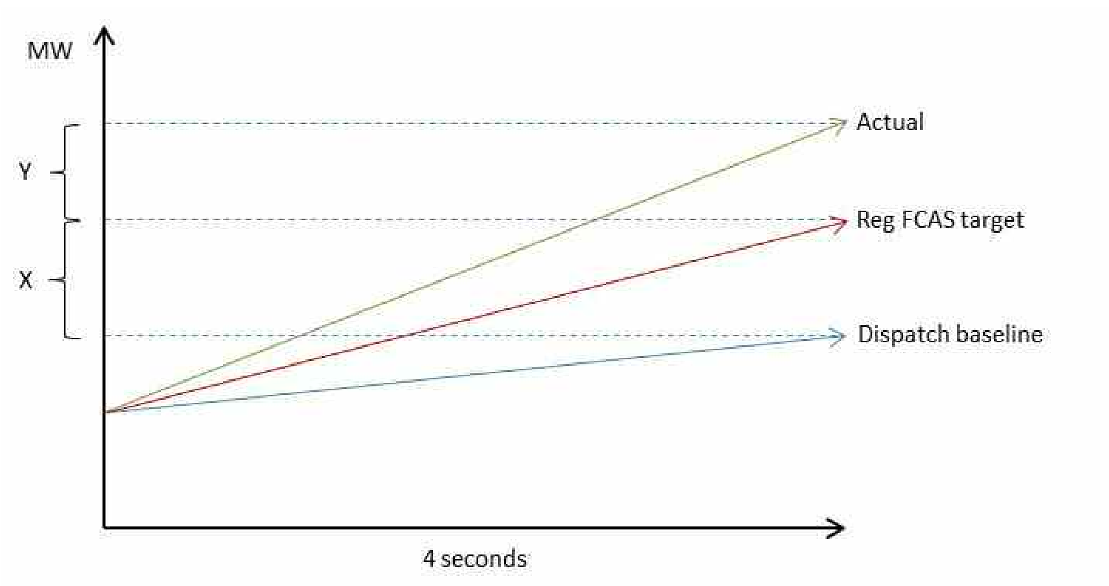
An example of the fair value payment calculation is illustrated in Figure A.7. In this case, a generating unit is given an initial dispatch target (blue line), which is updated to a higher MW output in response to AGC signals for the provision of regulating FCAS (red line). The

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

difference between the initial target and the updated target is equal to X MW. However, actual output of the generating unit ends up higher than the updated AGC target (green line), i.e. the generating unit outperforms its regulating FCAS target. The difference between the actual output and the updated AGC target is equal to Y MW.

If the system frequency is going down then the generating unit's excess generating output is providing a helpful contribution to system frequency. As such, the generating unit would receive a payment through the deviation pricing mechanism. This payment would be equal to the deviation price multiplied by the difference between the initial dispatch baseline (blue line) and the actual output (green line), which is X+Y MW multiplied by the deviation price. However, the generating unit is already paid for the enablement of the regulating FCAS, so the generating unit has in fact only over-performed against its target by the difference between the actual output (green line) and the regulation FCAS target (red line), which is Y MW. The generating units should therefore pay back to AEMO a fair value payment equal to the deviation price multiplied by the difference between the initial dispatch baseline (blue line) and the regulation FCAS target (red line), which is X MW multiplied by the deviation price.

Figure A.7: Fair value payment for the provision of regulating FCAS



Settlement balancing would also need to be made with respect to the recovery of regulating FCAS costs. Currently, regulating FCAS costs are allocated using causer pays contribution factors. It is possible that these arrangements could stay in place and operate alongside the deviation pricing mechanism. However, the structure of incentives that this may create is unclear.

Alternatively, the costs of regulating FCAS could be recovered through an uplift tariff on deviation prices applying to those participants with harmful deviations. This could either be in the form of an amount added to the price charged or an amount subtracted from the price paid. This uplift tariff would vary from time to time in order to balance settlements.

Long-term requirement for regulating FCAS

The introduction of a deviation pricing mechanism has the potential to significantly impact on the requirement for regulating FCAS. This impact will occur in circumstances where the incentives provided by deviation pricing are sufficient to encourage a significant proportion of market participants to act in a frequency responsive mode. In so doing, it would be expected that frequency would move to being much more tightly held around 50 Hz.

In practice, there may be the potential to rapidly move to the removal of the current purchase of a fixed volume of regulation FCAS and simply set the volume of regulating FCAS purchased dynamically on a dispatch interval by dispatch interval basis reflecting the effectiveness of the primary frequency control response in the previous dispatch interval (proxied by any change in accumulated time error). This would have the benefit of ensuring that the amount of regulation FCAS purchased was minimised and reflective of current needs thereby minimising total cost. Over time, this could also see the volume of regulating FCAS required decreasing significantly.[95]

With the introduction of a deviation pricing mechanism, regulating FCAS providers would have a choice to continue to participate in the provision of regulating FCAS or maximise their opportunities under the deviation pricing mechanism.

It is likely that unconventional technologies would prefer the deviation pricing mechanism. Under the regulating FCAS framework, a participant must provide a structured bid to AEMO together with ramp rate limits and other criteria. These arrangements are more likely to suit conventional technologies with stable costs and capabilities. Unconventional technologies may prefer to choose their own response rather than leaving it up to AEMO's dispatch algorithm.

Alternatively, providers of regulating FCAS may attempt to improve their response characteristics so as to over-perform on their FCAS requirements and thereby receive additional payments under the deviation pricing mechanism. These providers may wish to remain as participants in the regulating FCAS markets.

Another factor to be considered by participants is the respective levels of risk under the different frameworks. An enabled regulating FCAS provider is paid whether its response is required or not, whereas deviation payments are paid only for actual performance when required. This difference is even starker in the contingency markets where participants would only be paid occasionally under a deviation pricing mechanism when contingencies occur.

In the case of the regulating FCAS market, the dispatch of headroom occurs through enablement payments made to providers of the regulating FCAS. The economic trade-off

95 In this case there may only be a small volume of regulating FCAS required to manage time error correction. Much of this time error may be caused by forecasting error and so it may be preferable in this circumstance that the causer pays arrangements are removed and replaced with a simple smeared cost allocation.

occurs explicitly through participants' bids in both the energy and FCAS markets and through the co-optimisation process in NEMDE. This provides a greater level of confidence that the FCAS is available to be provided. However, this certainty comes at the expense of efficiency and is unlikely to be as necessary for the purposes of maintaining system security for frequency deviations within the normal operating band. Furthermore, while the deviation pricing mechanism does not explicitly pay for the enablement of FCAS, if all providers chose not to maintain headroom, there would be a strong and immediate price signal for providers to back off as soon as the frequency deviated.

The level of confidence in the availability of services from central procurement may be more suitable for contingency FCAS where the occurrence of contingency events poses a greater risk to system security.

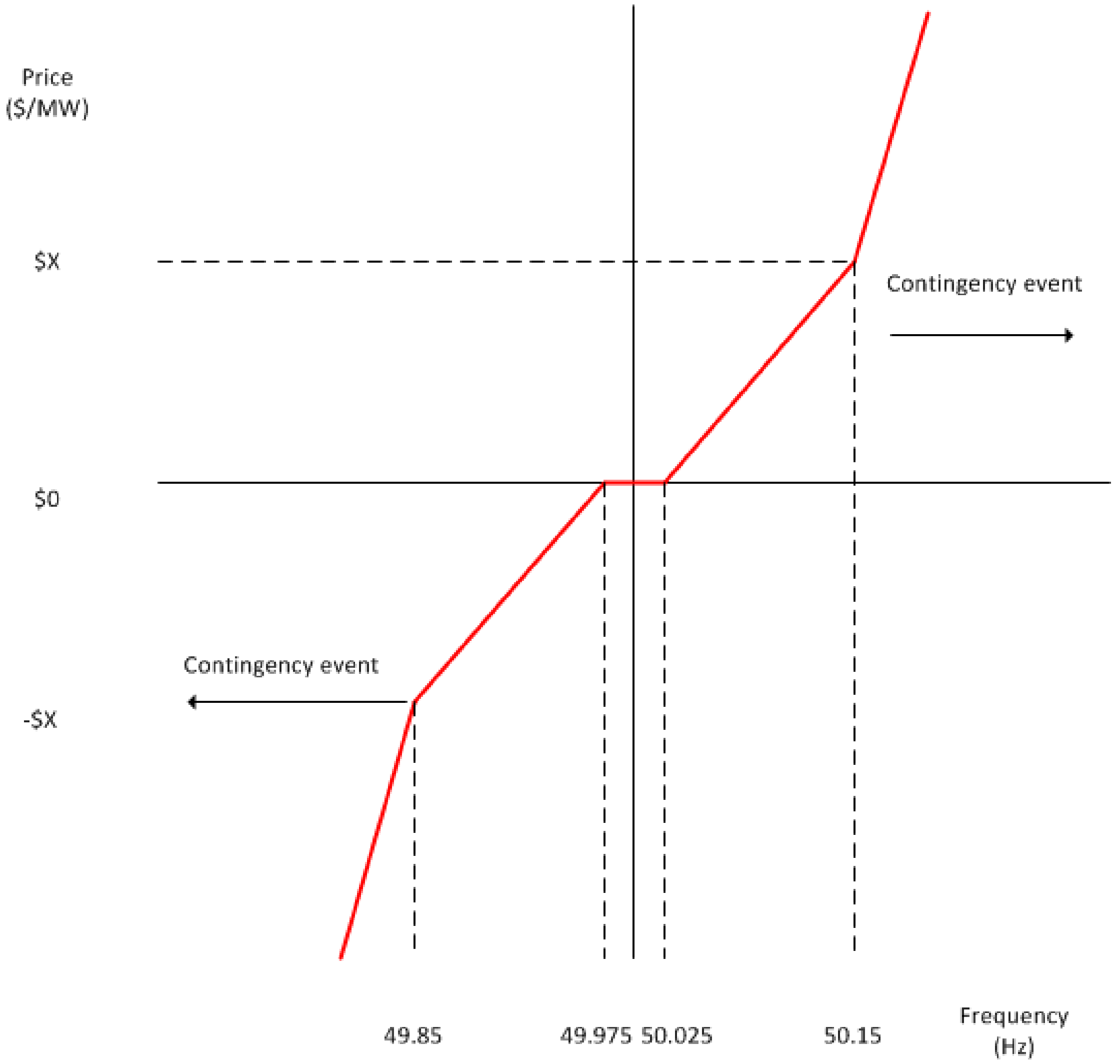
A.2.6 Deviation pricing of contingency FCAS, FFR and inertia

As discussed above, a deviation pricing mechanism appears to have attractive characteristics for application to frequency response within the normal operating band. Conceptually, it is possible to extend the mechanism to the existing contingency FCAS services as well as inertia and FFR. This section explores the potential application of a deviation pricing mechanism to these services.

Extending the mechanism to contingency FCAS

Under a deviation pricing mechanism, 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. This is shown below in Figure A.8.

Figure A.8: Extending the price function to contingency FCAS



Note: This figure extends Figure A.6 to reflect a possible extension of a normal operating frequency band deviation price function into the contingency frequency control space. As such, it has the same characteristics as Figure A.6 with respect to a $0/MWh dead band around 50 Hz and a negative price for deviations below 50 Hz but no longer plateaus at the edge of the normal operating frequency band. Instead it includes a price function that is steeper after leaving the normal operating frequency band in order to provide enhanced incentives for frequency responsiveness in this space.

Under the existing framework, an enabled FCAS provider is paid whether its response is required or not, but deviation payments are paid only for actual performance when required. This difference is most pronounced in the contingency markets, where an enabled FCAS provider is paid continuously, whereas an autonomous provider will be paid only on the rare occasion that a contingency occurs. This means that the income stream under the current framework is more stable and lower risk.

A key difference between regulating and contingency services is the random distribution over time of contingency events. As highlighted inTable A.1 below, on the mainland in 2017, contingency events occurred at the rate of around one event every 5 days or one event every 1,600 dispatch intervals whereas regulating services are continuously, and increasingly fully, activated in each dispatch interval.

Table A.1: Number of contingency events in 2017

	LOAD	GENERATION	OTHER	TOTAL
Mainland	19	39	8	66
Tasmania	32	10	157	199

Source: AEMO

A further critical difference is that, for frequency control in the normal operating band, where a large proportion of market participants operate in a frequency responsive manner, this should decrease the total need for regulating FCAS. This will not be the same for contingency services in that the volume of service required (headroom in MWs) will not decrease with an increase in the number of market participants acting in a frequency responsive manner, but rather is determined by the expected size of the largest credible contingency.

These differences may challenge the adoption of a deviation pricing mechanism for contingency events. Given the random distribution of contingency events, an individual generator cannot guarantee that they will be actively generating when a contingency event occurs and as such their expected return from a deviation pricing approach may be uncertain which in turn may mean that sufficient headroom to ensure a secure system is not maintained. As such, incentives under a deviation pricing mechanism would need to be sufficiently large to account for these factors (as shown in Figure A.8 by the steeper price function outside the normal operating frequency band).

Given the much higher degree of confidence required of the availability of contingency services, we consider that a deviation pricing mechanism is likely to be better suited to limited application to frequency variations within the normal operating frequency band.

However, a principal benefit of applying a deviation pricing mechanism to contingency FCAS is that it would eliminate the need to categorise the provision of the existing services into different timeframes. The existing timeframes (6 second, 60 second and five minutes) reflects a ‘traditional’ generation mix and therefore may not adequately support new technologies and the services needed as the power system changes. Under a deviation pricing mechanism, participants are paid in proportion to the profile of the frequency response they provide, without the need to register this response ahead of time or fit their response to specific timeframes.

A further benefit is that the participant that causes the contingency will likely face a significant charge that is proportional to their impact on frequency. This would address the existing issue with contingency FCAS frameworks which tend to smear the costs across multiple participants and therefore do not provide appropriate incentives for participants to reduce their potential impact on the need for frequency control services.

Measuring the speed of response

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. In this case, metering with a resolution of one second or less may be required.

The deviation interval would also need to be reduced in order to adequately reflect the rapidly changing value of frequency deviations following the contingency event. This period may only need to last for up to 30 seconds but would require a much finer resolution of deviation intervals. Initially, this may only need to be as short as one second but may go lower to 100 milliseconds in order to be able to appropriately value fast frequency response (FFR) technologies.

Participants in the fast deviation settlement would be those participants that are capable of providing fast frequency response (so that they can be rewarded) and those participants whose failure would trigger a large frequency excursion (so that they can be charged), e.g. large generating units.

Other participants would not need to participate in the fast deviation settlement, and therefore would not need to have high speed metering capability. However, for any 30-second period post contingency, the four-second deviation prices over that period would need to be the average of the sub-second deviation prices in order to make sure that deviation settlements continue to balance in aggregate.

Extending the mechanism to FFR and inertia

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 minimum required levels of inertia in sub-networks of the NEM and for TNSPs to maintain these minimum levels if a shortfall has been identified.

On 29 June 2018, AEMO published the inertia requirement methodologies and minimum inertia levels for the NEM.[96] AEMO has declared that there are no inertia shortfalls in the NEM at this time.

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. Currently, there are no arrangements to pay for this additional inertia. A number of stakeholders have

96 AEMO, Inertia requirements and inertia shortfalls, 29 June 2018.

supported the introduction of a mechanism to pay for additional inertia and faster response technologies.[97]

Pricing FFR and inertia

Under a deviation pricing mechanism, synchronous generators would receive a payment for the inertia they provide as frequency is deviating away from 50 Hz. This is because their rotating units will transfer some of their kinetic energy into electrical output as they slow down.

However, as the frequency moves back towards 50 Hz, the opposite will occur. In this case, synchronous generators will have negative deviations as some of their mechanical output is absorbed by the accelerating power system. The deviation charges imposed may largely cancel out the previous payments received.

Inertia does not act to restore the frequency to 50 Hz. Instead, the principal value of inertia lies in its ability to slow the rate of change of frequency (RoCoF). In order to properly value the contribution of inertia, a separate RoCoF component could be added to the deviation price function to provide an uplift on the price as a function of the value of RoCoF. This RoCoF component would need to have a very steep slope to reflect the very high value of deviations when RoCoF becomes large.

With this additional RoCoF component, inertia will automatically become valued as it becomes scarce. The rewards will increase over time as system inertia reduces and typical levels of RoCoF become larger. Technologies that are capable of providing FFR will also be rewarded through this additional component of the price function by rapidly injecting or withdrawing power to limit the overall RoCoF.

Measuring the speed of response

Extending the mechanism to value inertia and FFR will require high speed metering for those participants that wish to be paid for the provision of inertia or FFR. High speed metering would also be required for those participants that are large enough to create a significant contingency in order that they are appropriately charged.

While large participants are unlikely to want to be charged under the mechanism, it is likely that these participants will be synchronous generators and will therefore also have an incentive to install high speed metering in order to be paid for their inertia.

As with the extension to contingency FCAS, the deviation interval would need to be reduced in order to adequately reflect the rapidly changing value of frequency deviations following the contingency event. This period may only need to last for up to 30 seconds but would require a deviation interval of perhaps 100 milliseconds in order to be able to appropriately value the inertia and FFR technologies.

97 Submission on the draft report: Hydro Tasmania, p. 3; Snowy Hydro, p. 9; Energy Queensland, p. 7; Clean Energy Council, p. 6; Tesla, p. 7.

B STAKEHOLDER RESPONSES TO DRAFT RECOMMENDATIONS ON FREQUENCY CONTROL DURING NORMAL OPERATION

The Commission considers that the current regulatory arrangements do not adequately incentivise the provision of primary frequency control to assist in frequency regulation during normal power system operation (primary regulating services). In response to this, the Commission has developed a program of work in collaboration with AEMO to maintain and improve frequency performance during normal operation now and into the future. A discussion of the AEMC's long term approach to developing and implementing a framework for primary frequency control is set out in Appendix A.

The future program of work has drawn on stakeholder feedback in response to the Commission's draft report published in March 2018. This Appendix summarises stakeholder feedback and sets out the Commission's analysis and approach in relation to the recommendations that were set out in the draft report. The draft report included two draft recommendations intended to encourage the provision of primary regulating services.

- Draft recommendation 1 related to the improvement of existing frameworks for the allocation of costs associated with regulating FCAS (causer pays) to remove disincentives for the provision of primary regulating services
- Draft recommendation 2 related to the development of new or revised mechanisms to providing incentives for the provision of primary regulating services.

The remainder of this appendix is structured as follows:

- Section B.1 sets out the Commission's revised considerations in relation to potential improvements to the existing causer pays arrangements.
- Section B.2 sets out the Commission's revised considerations in relation to the options for the provision of primary regulating services that were identified and discussed in the draft report.

B.1 Improvements to existing frameworks

The draft report explored three aspects of the current market and regulatory arrangements that relate to the reduction of primary frequency control during normal operation, including:

- the requirements in the NER relating to compliance with dispatch instructions.
- 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 regulating FCAS contribution factor procedure (causer pays)

In relation to the first two issues, the AEMC concluded in section 5.3.1 of the draft report that:

- Under the NER, a generator varying its output as a consequence of the generating unit automatically responding to changes in system frequency is not inconsistent with a generators obligation to comply with its dispatch instructions.[98]
- Under the NER, AEMO is responsible for determining the operational settings for the AGC system and the arrangements for the activation of regulating FCAS. AEMO is in the process of reviewing the settings for the AGC system and the static and dynamic quantity of regulating FCAS procured to contribute to the management of frequency during normal operation.

In relation to the third issue, the draft report included a draft recommendation to improve AEMO's causer pays procedure by removing disincentives for the provision of active primary frequency control during normal operation.

DRAFT RECOMMENDATION 1 - Recovery mechanism for regulating FCAS costs - Causer pays

(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.

Section B.2.1 of this appendix sets out stakeholder feedback in relation to this draft recommendation along with the Commission's commentary on stakeholder feedback and recent developments and related issues.

B.1.1 Changes to the regulating FCAS contribution factor procedure (causer pays)

A principal objective of the regulating FCAS cost recovery arrangements is to place a financial incentive on market participants to act in a way that minimises the need to procure regulating services. By imposing the costs of the services on those market participants that give rise to the greatest need for the services, there is an incentive for those market participants to minimise adverse impacts to system frequency, and therefore minimise the overall requirements for the services. Such an arrangement should reduce the costs of regulating FCAS in the long term interests of consumers while achieving the objective of a secure power system.

The Commission is of the view that arrangements for financial incentives are likely to be efficient and effective where:

98 See clause 4.9.4(a)(4)(ii) of the NER.

- transparent procedures allow participants to understand how their actions relate to the costs they are likely to incur; and
- there is an alignment of participants' impacts on system frequency and the costs they incur.

Transparency and complexity of the causer pays process

When the arrangements are not transparent, or unnecessarily complicated, participants may misinterpret the likely costs associated with their actions, giving rise to potentially unintended consequences.

The current causer pays arrangements for the recovery of the costs of regulating FCAS are an example of a complex and opaque incentive framework. The draft report set out recommendations for how these arrangements could be improved. Part 2 of draft recommendation 1 recommended that AEMO provide greater clarity on how the causer pays procedure works and how the specific frequency indicator (FI) variable, that generator performance is measured against, is calculated and applied.

Alignment and shortening of the sample and application periods

AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[99] Currently, AEMO has chosen to adopt a 28-day averaging period for the calculation of the contribution factors as outlined in AEMO's causer pays procedure.[100] Taken together with the notice period, this means that the allocation of regulation FCAS costs for a particular 28-day period is based on performance contribution factors determined over a four week period commencing around six weeks earlier.

The misalignment of the application of costs with the causers of the costs has the potential to give rise to unintended incentives. Market participants may gain financial benefit from acting in a way that is contrary to the intention of the incentive framework.

The draft report noted 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. Draft recommendation part (a)(i) recommended to align the period for calculation of contribution factors with the period over which the costs are incurred. Preferably, the calculation of contribution factors should be based on the five-minute dispatch interval to achieve consistency with the energy market.

Draft recommendation part (a)(ii) recommended 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.

99 Clause 3.15.6A(na) of the NER.

100 AEMO, Regulation FCAS contribution factor procedure – DRAFT Version 6, April 2018, p.18.

AEMO's response

Transparency and complexity of the causer pays process

AEMO expressed support for draft recommendation 1 part (b) to clarify the regulating FCAS contribution factor procedure and provide increased visibility of FI data.[101] On 6 April 2018, AEMO published a draft determination and draft procedure as part of its *Regulation FCAS contribution factor "Causer Pays" procedure consultation*. AEMO's draft report supports the publication of FI data in close to real time in order to provide participants with better information on which to make operational decisions to improve frequency performance.[102] Along with the draft determination, AEMO published a revised causer pays procedure that was amended to improve clarity, readability, accuracy and consistency.[103]

Alignment and shortening of the sample and application periods

AEMO did not support draft recommendations 1(a)(i) to align the period for calculation of the contribution factors with the period over which the costs are incurred. AEMO indicated in its recent analysis that:[104]

> "there were insufficient benefits to warrant changing to more dynamic factors" and that such a change showed "the potential for undesirable consequences[…] including increased volatility, lack of certainty, and disconnection between incentives to avoid costs and maintaining reliability and security."

AEMO's draft report for the *Regulation FCAS contribution factor "Causer Pays" procedure consultation* recognised that an advantage of aligning the sample and application period for contribution factors would be to "allow facilities to better respond to changing FCAS costs."

However, AEMO notes a disadvantage of such an arrangement as being the promotion of the "operation of a power system where facilities are de-committed during periods of high FCAS prices, which may undermine security and reliability."[105] AEMO is concerned that the alignment of the sample and application period may create an incentive for generators with large contribution factors under causer pays to de-commit when a local requirement for regulating FCAS, for example in South Australia, results in very high FCAS prices, as occurred on 23 January 2017.[106]

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101 AEMO, submission to the draft report, 26 April 2018, pp.4-5.

102 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018, p.24.

103 AEMO, Regulation FCAS contribution factor procedure – Version 6 [DRAFT], 6 April 2018, p. 2.

104 AEMO, submission to the draft report, 26 April 2018, p. 4.

105 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018, p. 15.

106 On 23 January 2017, an unplanned single circuit outage on the double circuit 500kV Mortlake to Heywood transmission line created the credible risk that South Australia could island (if there was a subsequent failure of the remaining 500kV Mortlake to Heywood line.). Under this situation, AEMO is required to procure 35 MW of raise and lower regulation services from within South Australia to manage this risk of South Australia islanding. Following this particular outage the price for local raise regulation services reached $14 000/MW for six consecutive dispatch intervals, and the price for local lower regulation services reached $13 800/MW for seven consecutive dispatch intervals. See: AER, Report into market ancillary service prices above $5000/MW – South Australia – 23 January 2017, 1 September 2017. p. 5.

Where the sample and allocation periods are separate, this incentive does not exist as the contribution factors, including the weighting by generation output are already decided from the previous period, and do not change if the generator chooses to bid unavailable.

AEMO acknowledges that the use of real time factors would allow facilities to react to changing FCAS costs. However, AEMO suggests that this may also lead to a lack of cost certainty associated with a participant's regulating FCAS cost burden, potentially leading to the de-commitment of facilities in an extreme effort to limit exposure to the related costs.[107]

Nevertheless, AEMO's draft report for the *Regulation FCAS contribution factor "Causer Pays" procedure consultation* acknowledges the broader challenges in managing frequency control in the NEM and that in the "longer-term it is likely there will be a need for more dynamic quantities of regulating FCAS." AEMO noted that given the changes underway in the power system, in the future:[108]

> "the existing arrangements for recovery may no longer be appropriate, and some form of real-time recovery (which might include real-time contribution factors) may be more appropriate. On that basis AEMO considers that it would be prudent to retain the existing timing, and for real-time factors to be assessed as part of the AEMC's Frequency Control Frameworks Review."

Removal of the ten day notice period

AEMO's submission does not indicate a strong preference for or against draft recommendation 1 part a(ii) to remove the ten business day notice period between AEMO publishing and applying contribution factors. Rather, AEMO suggests that, "Market Participants are best placed to provide advice on the value-add that would result from this recommendation compared to the current approach." AEMO notes that any subsequent rule change on this matter should consider the time and cost to augment internal AEMO procedures to remove the current ten day notice period.

Stakeholder response

Transparency and complexity of the causer pays process

Most stakeholders supported draft recommendation 1(b); that AEMO provide greater clarity of the causer pays procedure and the specific FI variable that generator performance is measured against. ENGIE noted:[109]

> "there is currently a level of uncertainty and confusion regarding the details of the causer pays calculations. As noted in the draft report, it is important that participants are able to calculate their own contribution factors so that they can

107 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018, pp. 14-15.

108 Ibid., p. 15.

109 ENGIE, Submission to the draft report, 26 April 2018.

achieve confidence that they understand how they are derived and applied. Once participants have a better understanding of these factors, they will be better placed to respond appropriately to them, which should lead to an improvement in frequency performance."

Alignment and shortening of the sample and application periods

Stakeholder views were mixed on draft recommendation 1 part a(i) to align the period for calculation of the contribution factors with the period over which the costs are incurred.

A number of stakeholders supported the shortening and alignment of the sample and application periods for the allocation of regulating FCAS costs.[110] These stakeholders agreed that such a change would more accurately map generator behaviour against power system need for frequency control services. Meridian Energy noted that the current cost recovery mechanism is, "failing to deliver value for money to consumers and requires significant amendments to ensure it delivers against the National Electricity Objective."[111] CS Energy noted that the suggested change would be a vast improvement from the current approach. It suggested that increased precision would be achieved by the calculation of contribution factors on a four second basis, in order to incentivise generator control engineers to tune governor control systems to optimise performance on a four second basis.[112]

ENGIE supported AEMO investigating whether the link between the costs associated with the provision of a service and the drivers that create the need for the service can be improved. However, ENGIE suggest that the AEMC should not pre-empt the outcome of AEMO's review in any recommendation relating to the consideration for shortening the timing of the sample and application periods.[113]

A number of other stakeholders did not support such changes.[114] Hydro Tasmania opposed any reduction or alignment of the sample and application period, reiterating AEMO's concern in relation to the potential for increased volatility of contribution factors and the potential for perverse outcomes. Hydro Tasmania stated that the current arrangements provide generators with an incentive to follow targets in order to manage the uncertain risk of future FCAS prices.[115] Origin Energy supported reducing the sample and application periods from 28 days to 14 days and noted that:[116]

> "The appropriate period should examine the ability for generators to adjust their responses to pricing outcomes, AEMO workload on producing and refining data sets, and the impact that pricing certainty has on driving better frequency outcomes."

AGL noted that:

110 Submissions to the draft report: AEC, p.1; CS Energy, p.3; ERM Power, p.4; Meridian Energy, p.1; S&C Electric, p.6.

111 Meridian Energy, submission to the draft report, p.1.

112 CS Energy, submission to the draft report, p. 3.

113 ENGIE, submission to the draft report, p. 2.

114 Submissions to the draft report: AGL, p.3.; Hydro Tasmania, pp.1-2.; Origin, p.3.

115 Hydro Tasmania, submission to the draft report, pp. 1-2.

116 Origin Energy, submission to the draft report, p. 3.

> "Improving the price signal provided by the causer pays procedure may assist participants to more proactively manage their exposure to causer pays factors. However [...] we have concerns regarding whether the practicalities of this change or the potential impact on generator behaviour would outweigh any potential benefits."

Removal of the ten day notice period

Most stakeholders did not communicate any views in relation to reducing or removing the ten business day notice period between publishing and applying contribution factors could.

An exception was Meridian Energy who indicated support for a reduction of the current ten day notice period.[117]

Other issues raised by stakeholders

CS Energy proposed a number of additional changes to the netting arrangements in the causer pays procedure to improve the accuracy of the allocation of regulation FCAS costs.[118] The proposed changes relate to how the procedure addresses the following issues:

- regional netting of load forecast error
- treatment of metered non-scheduled loads
- removal of any distinction between 'metered non-scheduled' facilities and 'metered scheduled' facilities
- the allocation of costs between the total of metered and the total of non-metered (residual) participants should be determined at a system level
- costs related to the need for regulating raise services should be allocated separately to costs related to regulating lower services.[119]

The changes suggested by CS Energy were considered through AEMO's *Regulation FCAS contribution factor "Causer Pays" procedure consultation,* While AEMO saw merit in the 'CS Energy netting proposal', they concluded that further work was required to understand its impact and whether its implementation would deliver an overall benefit.[120]

Commission analysis

Alignment and shortening of the sample and application periods

The Commission acknowledges the concerns raised by AEMO and other stakeholders in relation to the potential risks associated with significant changes to the sample and application periods in the causer pays procedure. AEMO has investigated this issue through its recent consultation on the causer pays procedure and has determined to retain the existing sample and application period timings in the short term.[121]

117 Meridian Energy, submission to the draft report, p. 1.

118 CS Energy, submission to the draft report, pp. 3-4.

119 CS Energy, submission to the draft report, p. 3.

120 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation - draft report and determination, 6 April 2018, pp. 12-13.

121 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation - draft report and determination, 6 April 2018, p. 15.

However, the Commission considers that scenarios in which participants face an incentive to de-commit their capacity during periods of high FCAS prices are likely to be rare. Furthermore, participants may employ strategies to mitigate the associated financial risks, such as implementing operational changes to improve their contribution factors or by providing regulating FCAS themselves.[122]

If the risk of perverse outcomes was shown to be persistent, then the costs of regulating FCAS could be smeared across all market participants within a particular region on a pro rata basis, for the period of time that a local FCAS requirement was in place. While this approach would remove the incentive for a market participant to de-commit in order to manage its exposure to regulating FCAS costs, such an approach would require a change to the procedure in order to be implemented.

CS Energy's additional proposed changes to netting arrangements are being considered through AEMO's consultation on the *Regulation FCAS contribution factor "Causer Pays" procedure*. AEMO has acknowledged that the CS Energy netting proposal will require further consideration following the conclusion of the current consultation.[123]

Removal of the ten-day notice period

Under the NER, AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[124]

The Commission maintains that there may be benefits associated with the removal or reduction of this ten-day notice period based on the view that the causer pays incentive is likely to be more effective if the performance measurement is closely aligned to the application of associated costs, preferably in real time. As such, any benefits from reducing or removing the ten-day notice period are only likely to be realised if the change is undertaken in combination with an alignment of the sample and application periods.

Transparency and complexity of the causer pays process

The Commission acknowledges the recent developments made through AEMO's consultation on the *Regulation FCAS contribution factor "Causer Pays" procedure* in relation to improving the transparency and readability of the procedure and the plan to publish FI data in close to real time.

Conclusion and proposed approach

AEMO has determined to maintain the existing 28-day notice and application periods at this time.[125] The Commission understands that this determination is intended to reduce the

122 Under clause 3.15.6A(k)(5)(ii) of the NER, a market participant is not considered to have contributed to a frequency deviation during a dispatch interval if it is enabled to provide a market ancillary service during that interval and responds satisfactorily to a control signal from AEMO.

123 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018, p.13.

124 Clause 3.15.6A(na) of the NER.

125 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation – draft report and determination, 6 April 2018, p. 15.

volatility in relation to allocation of regulation FCAS costs and support long term commitment of market participants to stable operational settings.

The Commission also acknowledges that the actions proposed to be undertaken by AEMO to improve the causer pays procedures, including:

- a consolidation and clean-up of the procedure and improved explanation of key elements and themes.
- an amendment to the procedure to ignore performance data for time periods where frequency indicator and frequency are mismatched
- publication of frequency indicator data close to real time

The Commission maintains the view that an efficient framework is one in which there is an alignment of participants' impacts on system frequency and the costs they incur. As such, an alignment of sample and application periods under the causer pays arrangements may have some benefits.

However, in light of concerns raised by AEMO and other stakeholders, the Commission is of the view that it is likely to be more appropriate to incentivise the provision of primary regulating response through a separate performance-based mechanism that targets automatic frequency response. The development of such a mechanism is discussed in detail in Appendix A.

In relation to improvements to transparency, the Commission supports AEMO's recent revision of the causer pays procedure, including the improvements to the structure and explanation of the procedure and AEMO's commitment to publish frequency indicator data close to real time.

AEMO's draft report on the causer pays procedure consultation identified seven additional areas for improvement of the causer pays procedure. However, AEMO states that the immediate priority is addressing issues relating to primary frequency control and as such these additional proposals are not planned to be immediately actioned, but will be considered through subsequent consultations. The Commission supports the continued refinement of AEMO's causer pays procedure, specifically through the actioning of the remaining alternative arrangements recommended by AEMO through its draft report.

B.2 Provision of primary regulating services

In its draft report, the Commission concluded that more primary regulating response is needed to maintain good frequency performance under normal operation. The draft report identified a number of potential options for the provision of increased primary regulating response and set out the Commission's initial assessment of these options, as summarised below.

1. The provision of primary response along with the provision of regulating FCAS

Under such an arrangement, a generator that is enabled to provide a regulating service would provide the service either as a response to a change in locally measured frequency as well as in response to a signal from the AGC system.

2. Narrowing of trigger settings for the existing contingency services

Under this option, the trigger points for some or all of the existing contingency services would be narrowed through changes to the frequency operating standard and/or the market ancillary service specification.[126]

3. The mandatory provision of a primary regulating response

A mandatory requirement could be placed on market participants for them to provide a primary regulating response. 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).

4. Procurement of response and headroom via contracts

The contract procurement of primary regulating services would involve the specification of performance characteristics and the required quantity of primary frequency response by AEMO. These services would then be procured on a periodic contract basis by AEMO or potentially a TNSP as is the case for other non-market ancillary services such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS).

5. Development of new markets

Setting up separate markets for raise and lower primary regulating services similar to the existing market ancillary services would allow AEMO to prescribe the required amount of each type of service. The provision of these services could then be dynamically optimised in response to changing power system conditions.

5. Introduction of incentive payments for primary regulating response through changes to the causer pays arrangements

Incentives for the provision of a primary regulating response could be established through changes to the existing causer pays procedure by paying participants for positive responses to changes in system frequency.[127]

Recommendation 2 from the draft report recommended further investigation of the potential arrangements for the implementation of options A and F. Sections B.2.1 and B.2.2 provide a summary of stakeholder feedback to options A and F and the Commission's analysis. Section B.2.3 summarises stakeholder feedback on the remaining options B to E, and the Commission's analysis.

This report also sets out the Commission's proposed next steps.

Stakeholder views on the provision of primary regulating response

Stakeholders broadly consider that providers of primary frequency control should be remunerated for the costs of providing the service. There is general agreement among

126 See clause 3.11.2 of the NER. The fast, slow and delayed services are commonly referred to as contingency services. Currently the trigger settings for these services are defined by AEMO through the market ancillary service specification with reference to the normal operating frequency band which is defined in the frequency operating standard as 49.85 Hz - 50.15 Hz.

127 The "causer pays" procedure is a common name for the procedure for determining contribution factors for the recovery of costs related to regulation services. NER clause 3.15.6A (k).

stakeholders that the long term goal should be to develop and implement a mechanism to allow potential providers of primary frequency control to compete and innovate to provide sufficient levels of this service.

AEMO also considers that a form of payment mechanism would be the most effective solution for the procurement of PFC in the longer-term. However, AEMO also suggests that the design of any mechanism must build on the underlying technical needs of the system, and as such proposes an approach in the short term to addressing the current need for increased primary frequency control during normal operation.[128]

AEMO intends to undertake trials and investigations to determine the specific engineering requirements necessary to achieve effective frequency control. These trials will involve AEMO coordinating the tightening of generator governor dead bands to within the normal operating frequency band for a period of time so that the impact of such changes can be assessed. AEMO is working with a group of industry power system experts from across the NEM to scope such trials.[129] AEMO undertook frequency control trials in Tasmania in May 2018 and is planning to undertake similar trials in the mainland later in 2018. A summary of the preliminary results from the Tasmanian frequency control trials is provided in Box 1 of Appendix A.

AEMO proposed that the design of any regulatory or market arrangements to deliver primary frequency control be considered on evaluation of the outcomes of these trials.[130]

AEMO recognised that there is an urgent need to prevent any further deterioration of frequency performance during normal operation related to the deficiency of primary frequency control. As such, AEMO proposes to work with the AEMC and stakeholders to determine the specifics of an interim solution to address this need.[131]

AEMO suggested that a potential short term solution may be:

> "A requirement for generators to provide PFC in the short-term via their governor control systems. We propose the cost of PFC would be incorporated into the cost of supplying energy to address the immediate need for improved PFC performance in the NEM."

AEMO suggested that effective primary frequency control requires a continuous service provision and that such a characteristic is best provided through the enablement of a significant proportion of the generation fleet.[132] AEMO has undertaken modelling based on

128 AEMO, submission to the draft report, 26 April 2018, p. 8.

129 AEMO, submission to the draft report, p. 8.

130 Ibid.

131 AEMO, submission to the draft report, pp. 6-8.

132 AEMO considers that effective frequency control within the normal operating frequency band requires a continuous and proportional modulating response to changes in frequency, which must be provided from a large proportion of online generating units. The majority of generation in the NEM is still thermal steam based generation with output that tends to change relatively slowly over time. A thermal steam generator may be able to provide a larger rapid change in generation output by drawing down on stored energy and pressure within the boiler, but the boiler pressure must then be restored before the rapid active power response can be repeated. As such, a small number of generators providing the required response may find it difficult to respond continuously to frequency variation under normal operating conditions while maintaining boiler steam pressure.

the current generation fleet that suggests that effective primary frequency control requires greater than 30% of online generation to be operating in a frequency responsive mode, each providing a small component of the required proportional response at any time.

Box 3 below presents the results of a modelling exercise that AEMO undertook to illustrate how a larger proportion of responsive units within the generation fleet translates to a smaller proportional response from each generating unit.[133] The graph shows how a generator's response to a given supply demand mismatch decreases as the proportion of online generating units providing primary frequency control increases. The chart also shows how the frequency deviation associated with the supply demand mismatch decreases as the proportion of responsive generation increases.

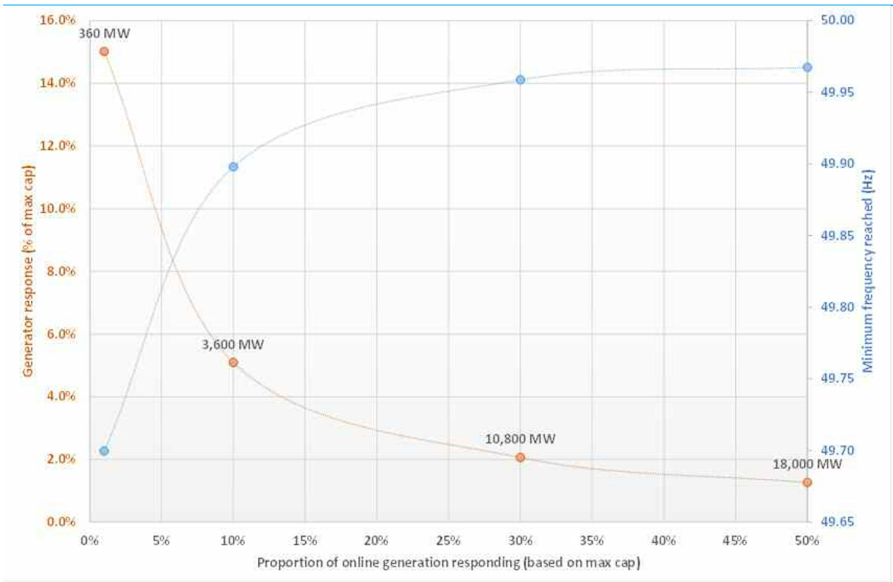
BOX 3: RELATIONSHIP BETWEEN GENERATION PARTICIPATION AND PRIMARY FREQUENCY RESPONSE PER GENERATING UNIT

AEMO has undertaken some basic mathematical modelling to show how the primary response of generators would behave for a 250MW supply-demand mismatch (equivalent to a 1 per cent error on a 22GW demand). The proportion of the online generation fleet that responds is varied (from 1 per cent to 50 per cent, or 360MW up to 18000MW).The chart below also shows the minimum (steady-state) frequency that would be reached based on the level of generation delivering a primary frequency response. These calculations assume:

- 22GW NEM demand
- 4 per cent generator droop
- 36GW total available plant online
- 0Hz dead band
- Available headroom of 14GW
- 1.5 per cent load relief.

133 AEMO, submission to the draft report, pp. 7-8.

Figure B.1: Frequency performance vs generation providing primary frequency response



Source: AEMO

In line with this alternative approach, the Commission has worked with AEMO to collaborate on the development of a work plan to chart the actions and proposed timeline to progress a program of investigations and policy development related to the frequency control frameworks. This work plan is described in Chapter 4. The Commission's approach to the development of longer term policy options is set out in further detail in Appendix A.

B.2.1 Provision of primary regulating response along with the provision of regulating FCAS - Option A

Under this arrangement, a market participant that is enabled to provide the regulating raise service would be required to provide both a primary response (i.e. primary regulating response) and a secondary response (i.e. traditional regulating FCAS). The primary component would be provided in response to a change in locally measured frequency while the secondary component would be in response to a signal from AEMO via 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 or load.

Hydro Tasmania included an example of such a control logic in its submission to the issues paper, which suggested that:[134]

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

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

- 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.

Stakeholder response

AEMO response

AEMO considers that an arrangement where providers of regulating FCAS are required to provide a primary regulating response is unlikely to deliver suitable levels or a sufficient distribution of primary frequency control.[135] The Commission understands that AEMO's view in relation to this option is based on the following concerns.

- Primary regulating response is a fundamentally different service to the secondary response provided through the existing regulation services. AEMO proposes that the procurement of both services through a single mechanism is not likely to effectively satisfy the power system needs for each specific service in terms of the required volume and distribution of primary frequency control.
- Currently, regulating FCAS is procured in blocks from a relatively small proportion of the entire generation fleet. If primary regulating response were provided as a bundle with regulating FCAS then the primary service may not always be available to be provided on a continuous basis, due to plant technical limitations.
- The requirement for service providers to be capable to provide both primary and secondary frequency response is likely to result in a reduction to the pool of regulating FCAS providers, leading to a reduction in the competitiveness of the markets for these ancillary services.

Other stakeholder responses

A number of stakeholders were of the view that this approach had problems in relation to the specification, provision and verification of the related services.[136] Stakeholders noted that the characteristics of a primary and a secondary response are different and that attempting to procure both types of response through a single mechanism was problematic. The following concerns were raised by stakeholders in relation to this option.

- A market participant that is not capable of providing both a primary and a secondary frequency response would be unable to bid to provide either service. Some existing providers of regulating FCAS may be unable to provide a primary regulating service and

135 AEMO, submission to the draft report, p. 8.

136 Submissions to the draft report: AEC, p.2; CS Energy, pp.7-8.; ENGIE, p.3; Origin Energy, p.2.

therefore such an arrangement may lead to a reduction in the competitiveness of the markets for regulation services.[137]

- Many generators are not able to adjust their generator governor dead bands dynamically on a five minute basis in response to changes in enablement for regulation services. As a result, a generator who wishes to provide regulating FCAS may end up providing the primary frequency response regardless of whether they are enabled in the regulating FCAS market. This creates an incentive for generators to withdraw some or all of their capacity from the regulating FCAS market to limit their exposure to the costs associated with the free provision of primary frequency control.[138]
- The blending of primary and secondary services is likely to impact the availability of boiler steam reserves for thermal generation plant to provide a contingency response if required.[139]
- It may be difficult to specify the combined service through the market ancillary service specification, which may delay the implementation of this option.[140]
- Assessment of the service delivery will be difficult as AEMO may struggle to differentiate the provision of each of the separate services.[141]

Commission analysis and approach

The Commission acknowledges the concerns raised by stakeholders in relation to the difficulty of implementing an approach that combines two different types of ancillary services. The operational challenges associated with providing both primary and secondary frequency response through a single enablement mechanism may reduce levels of competition in the provision of regulating FCAS. Additionally, the Commission acknowledges AEMO's concerns that such an approach may not deliver a sufficient level or distribution of primary frequency control.

In light of the submissions received from AEMO and other stakeholders highlighting the challenges with the implementation of this option the Commission recommends that Option A should not be investigated further at this time.

B.2.2 Introduction of incentive payments for primary regulating response through changes to the causer pays arrangements - Option F

This option is intended to reward market participants whose facilities contribute to helping to manage power system frequency through valuation of positive contribution factors determined through AEMO's causer pays procedure. The causer pays procedure determines a contribution factor for each market participant facility with four second metering with respect to how closely that facility follows its dispatch targets and whether any deviation from a dispatch target contributes to the need for regulation services. Under this procedure:

137 Submissions to the draft report: AEC, p. 2; Origin Energy, p. 2.

138 Submissions to the draft report: AEC, p. 2; CS Energy, pp. 7-8.; Origin Energy, p. 2.

139 CS Energy, submission to the draft report, p. 6.

140 Submissions to the draft report: AEC, p. 2; Origin Energy, p. 1.

141 ENGIE, submission to the draft report, p. 3.

- A negative net contribution factor represents performance that has, on average, contributed to the need for regulating FCAS.
- A positive contribution factor represents performance that has, on average, helped to manage system frequency.

Under the current procedure, contribution factors are calculated based on a 28-day sample period and these factors are netted across a market participant's portfolio of generation and load facilities. Any net positive contribution factors for each market participant are subsequently nullified.

Under option F as set out in the draft report, the nullification of net positive contribution factors would be removed and the causer pays procedure would be adjusted to allow payments to be made to market participants based on these remaining net positive contribution factors. These payments would incentivise market participants to operate their plant in a way that helps to manage system frequency.

As set out in the draft report, adopting this approach may have a number of implications, including:

- The cost of these incentive payments is likely to 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 or due to reductions in the prices bid by generators if the service is activated less. However, it is understood that regulating FCAS will continue to be required into the future and, as such, the cost is not likely to reduce to zero.
- Based on an equal valuation of negative and positive contribution factors, the residual charge paid by market customers is likely to increase as the total costs associated with frequency regulation increase.[142]

Positive contribution factor payments would create an additional cost that would need to be recovered from those participants with negative contribution factors and from the residual component that is charged to market customers.

Stakeholder response

AEMO response

AEMO indicated its support for performance based incentives to encourage the provision of ancillary services, including primary frequency control. However, AEMO is concerned that:[143]

> "introducing incentives for PFC into the existing causer pays mechanism, if not carefully considered, may lead to a further increase in the complexity of the process, as well as the potential for distortionary impacts."

142 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.

143 AEMO, submission to the draft report, pp. 5-6.

Other stakeholder responses

A number of stakeholders expressed support for further development of this option.[144]

The AEC and CS Energy expressed support for the implementation of this option as an interim mechanism; with the long term goal being the development of an explicit procurement mechanism for the delivery of primary regulating response.[145] The AEC requested that the Commission provide specific detailed analysis of how an incentive-based arrangement through the causer pays procedure would work before concluding this review.[146]

A number of stakeholders recognised that such an incentive mechanism could operate alongside and complement a separate procurement mechanism for primary regulating response.[147]

IES noted that the goal of AGC, regulating FCAS and the causer pays procedure is to provide slow moving integral control to correct slow or persistent frequency deviations. Primary frequency control provides a faster, proportional response to frequency deviations and should therefore be treated separately in terms of measuring the performance of market participants. IES noted that a measure of the need for a proportional response could be incorporated into the causer pays procedure. However IES proposed that “a better approach would be to develop a balanced deviations market in primary regulation and to leave the current arrangement for paying for AGC alone”.[148]

Engineers Australia argued that:[149]

> “Caution is brought to implementing any such changes until the consequences are fully understood from a systems perspective, and whether there is any overall benefit, or if this may be detrimental to frequency control.”

Commission analysis and approach

The Commission considers that the revision of the causer pays procedure to incentivise the provision of primary regulating response may be beneficial as an interim measure to help improve frequency performance during normal operation. However, the Commission acknowledges stakeholder concerns in relation to this option and recognise that it may not represent the ideal long term solution for delivering the required level of primary regulating service. The Commission has set out below an example description of this option to guide stakeholder consideration.

144 Submission to the draft report: AEC, p.3; ARENA, p.3; CEC, p.3; CS Energy, p.9-10; Origin Energy, p.1; Snowy Hydro, pp.6-7; Tesla, p.3.

145 Submissions to the draft report: AEC, p. 3; CS Energy, pp. 9-10.

146 Ibid.

147 Submissions to the draft report: AEC, p. 3; ENGIE, p. 4; Origin Energy, p. 1.

148 IES Advisory, submission to the draft report, p. 2.

149 Engineers Australia, submission to the draft report, p. 7.

Description of how this option may work in practice

An example of how this option F may work in practice is set out below in relation to the application of the causer pays arrangements to a simplified hypothetical power system with three generating units and a single generic load.[150] The table below sets out the hypothetical regulation FCAS contribution factors for a fictitious 28-day sample period. In this example, the regulation FCAS costs for the period are $1 million. Table B.1 sets out the allocation of costs based on a simplified version of the existing causer pays procedure, where net positive contribution factors are zeroed.

Table B.1: **Example contribution factors - current arrangements**

MARKET PARTICIPANT	NET CONTRIBUTION FACTOR (MPF)	ZERO POSITIVES	NORMALISE [MPF ÷ (20+30=50)]	COST PER PARTICIPANT
Generator A	0	0	0	0
Generator B	-20	-20	0.4	$400,000
Generator C	+5	0	0	0
Generic unmetered load (residual)	-30	-30	0.6	$600,000

Under the proposed option, the positive contribution factors would not be set to zero. In this case, the positive contribution factor of Generator C would be scaled and weighted with a resultant normalised positive factor of 0.1. This would represent a payment of $100,000 for the period. This additional payment of $100,000 would then be recovered from participants with negative contribution factors on top of their existing charges. The revised cost allocations become those set out in Table B.2.

Table B.2: **Example contribution factors - valuation of net positive contribution factors**

MARKET PARTICIPANT	NET CONTRIBUTION FACTOR (MPF)	NORMALISE [MPF ÷ (20+30=50)]	PAYMENT FOR POSITIVE CONTRIBUTION	COST PER PARTICIPANT
Generator A	0	0	0	0
Generator B	-20	-0.4	-	$440,000
Generator C	+5	+0.1	$100,000	-
Generic unmetered	-30	-0.6	-	$660,000

150 In this example the generic load does not have 4-second metering and therefore this participant represents the non-metered component of simplified system. As in the real power system, the non-metered residual incorporates the demand forecast error as a contribution to the need for regulating FCAS.

MARKET PARTICIPANT	NET CONTRIBUTION FACTOR (MPF)	NORMALISE [MPF ÷ (20+30=50)]	PAYMENT FOR POSITIVE CONTRIBUTION	COST PER PARTICIPANT
load (residual)				

In this example the valuation of positive contributions has increased the total costs of regulation services by 10 per cent and this cost increase has been born proportionally by Generator B, who has a negative contribution factor, and the generic load, which represents the residual component in the causer pays calculation.

The Commission notes that this example is intended to show the basic impact of the potential valuation of net positive contribution factors and does not account for the feedback impact of the incentive on generator behaviour and contribution factor outcomes. The Commission expects that the valuation of net positive contribution factors, along with the attribution of additional costs to participants with negative contribution factors, would provide an incentive for market participants to respond to changes in frequency in a helpful way. As a result it would be expected that the generators may decide to operate their facilities in a frequency responsive mode and provide primary regulating service to help manage the frequency during normal operation.

The expected result would be that the contribution factors for metered participants (Generators A, B and C in the example above) would be expected to increase on average resulting in reduced cost allocation to these participants and increases in positive contribution factors. This change in generator behaviour would be expected to also correspond to an improvement in frequency performance during normal operation and potentially a reduction in the quantity and cost of regulation services.

Estimated impact of valuation of positive contribution factors

In order to illustrate the possible impact of introducing payments for positive contribution factors, the Commission has analysed AEMO's participant performance factors for three recent 28-day periods commencing at the beginning of April 2018. This analysis calculated the magnitude of the positive portfolio factors that are currently being zeroed in order to assess the potential scale of payments that may be made. This analysis assumes that positive contribution factors are valued at the same rate as negative contribution factors.

Table B.3: **Illustrative magnitude of payment to positive MPFs**

	PERIOD 1	PERIOD 2	PERIOD 3	AVERAGE
Positive factor as % of total negative factors	10%	12%	15%	12%
Total in period	3,570,851	7,035,496	11,578,530	7,394,959

	PERIOD 1	PERIOD 2	PERIOD 3	AVERAGE
regulation FCAS recovery ($)				
Implied payments to positive factors ($)	358,945	827,660	1,776,967	987,857

Table B.3 shows that, on average over the period under analysis, total aggregated positive causer pays factors represented around 12 per cent of the value of total aggregated negative causer pays factors and that total payments for positive factors are estimated to average approximately $1 million per 28-day period.

In calendar year 2017, the cost of regulation FCAS was in the order of $98 million. Based on 2018 year-to-date costs (to mid-June) scaled to reflect a full year, the total cost of regulation FCAS in 2018 is expected to be significantly lower, perhaps in the order of $70 million. If the ratio of positive contribution factors to total negative aggregated contribution factors were to remain at around 12%, the total annual payment for positive contribution factors would be in the order of $8 million per annum. This may well be sufficient to provide a material incentive for participants to seek to increase their positive contribution to frequency control.

Challenges associated with the existing causer pays procedure

The Commission recognises there are challenges associated with utilising the existing causer pays procedure for the implementation of a performance-based price and reward mechanism to encourage primary regulating response.

- There is a level of stakeholder concern, confusion and distrust in relation to the causer pays procedure and as such there are challenges in clearly communicating the proposed changes and associated impacts. While AEMO's recent draft changes to the procedure go some way to alleviating stakeholder concerns, there remain a large number of areas for improvement that have been identified by AEMO for future action.[151]
- The payment of incentives on the basis of net positive contribution factors is likely to increase the cost burden on market participants with negative contribution factors and on market customers through the residual cost allocation. This may be concerning to certain stakeholders, especially where the operation of the procedure appears opaque, and the options to manage the associated financial risks are limited.
- The increase in the cost burden on market participants with negative contribution factors and on market customers through the residual cost allocation has the potential to magnify any distortionary outcomes inherent in the existing procedure. Therefore, a

151 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation - draft report and determination, 6 April 2018.

high degree of confidence is required in the accuracy of the procedure outcomes prior to implementation of such a change.

The Commission recognises that to the extent that the current procedure contains any distortionary effects, then the valuation of net positive contribution factors may magnify these effects.

Is the existing causer pays procedure the right mechanism for incentivising primary regulating response?

The existing causer pays procedure may be able to provide an incentive for generators to provide more primary frequency control, however this procedure is not designed with primary frequency performance as its primary target. The goal of the current procedure is to allocate the costs of regulation services to market participants based on the extent to which participants contributed to the need for those services. AEMO performs this by measuring generator performance relative to frequency indicator (FI) which provides a cumulative measure of the amount of corrective electrical power required to be added to (or removed from) the power system to restore the system frequency to 50Hz. As FI is not a direct measure of the system frequency, the causer pays procedure is an imperfect mechanism for incentivising primary frequency response.

Measuring the need for primary frequency control may require a different approach to measuring the need for secondary frequency control, or regulating FCAS. Based on AEMO's advice, the need for primary frequency control is based on the size of any expected supply demand mismatch and the allowable frequency deviation for such a mismatch.

In contrast, the need for regulating FCAS is based on AEMO's estimation of the number of megawatts of electrical power that need to be injected or removed to correct a given frequency deviation.[152] This concept is described in the Generator Group submission, which sets out two causer pays mechanisms for primary frequency control which are suggested to be more preferable than adjusting the existing causer pays arrangements for regulating FCAS. One mechanism is based on a participant's contribution to frequency deviations measured on a four second basis, the other mechanism is based on a statistical analysis of a participant's contribution to the general trajectory of the frequency variation which leads to the need for regulation services.[153]

On the other hand, while there are differences between measuring how participants contribute to the need for regulating FCAS and the need for primary regulating response, there is a degree of recognition that the regulating FCAS cost recovery mechanism can provide an incentive for market participants to be responsive to system frequency. For example the Australian Energy Council noted:[154]

> "Some of our members report that the crediting of positive contributions in causer-pays factors across portfolios does create an incentive for some voluntary provision

152 AEMO, Advice to the Frequency control frameworks review, 5 March 2018, p. 6.

153 Group of generators, Submission to the draft report, pp. 81-82.

154 AEC, submission to the draft report, 2018, p. 3.

of primary regulating response."

This same reason is behind one of AEMO's proposed changes to the regulating FCAS contribution factor procedure. As noted in section 2.1 of this appendix, AEMO plans to remove from the calculation regulating FCAS contribution data where the FI and the frequency are mismatched. AEMO notes that:[155]

> "Given the concerns raised through AS-TAG that this issue may be leading to incentives for generators to limit their frequency response within the normal operating frequency band, AEMO considers that resolution of this issue is a high priority."

This proposed action recognises that while FI and frequency are not equivalent, it is possible for the causer pays procedure to disregard instances where they are in opposition in an effort to reduce dis-incentives to providing active primary frequency control.

Implementation timeframe

One of the benefits of this option F is that the implementation timeframe may be shorter than that for the development of an explicit procurement mechanism for primary regulating response.

The implementation of this change would require a change to the NER to allow for payments to be made to market participants with positive net contribution factors and for the costs associated with these payments to be recovered from participants who are not metered or have negative contribution factors.[156] Following the rule change process AEMO would need to undertake a review and consultation to update the causer pays procedure.

The Commission expects that such a process may take in the order of 12-18 months from the receipt of a rule change request through to the subsequent implementation of the revised causer pays procedure by AEMO.

Conclusion and proposed approach

The Commission considers that this option F represents a potential interim measure to incentive the provision of primary regulating response.

Further discussion of the potential role of interim policy measures is included in Appendix A - section A.2.1.

However the Commission agrees with the Australian Energy Council, AEMO and CS Energy that the focus of regulatory reform should be on the development of an explicit procurement mechanism for primary frequency control over the long term.

155 AEMO, Regulation FCAS contribution factor "Causer Pays" procedure consultation - draft report and determination, 6 April 2018, pp. 23-24.

156 Clause 3.15.6A(a) of the NER sets out the ancillary service transactions that occur to allocate the costs associated with the procurement of ancillary services including the cost associated with procurement of regulating raise and regulating lower services. Clause 3.15.6A(i) then sets out how these costs are allocated to market participants on the basis of Market Participation Factors(MPF) which are calculated by AEMO through the regulation FCAS cost recovery procedure(causer pays).

The Commission considers that the development of such an explicit mechanism is likely to be more preferable as a long-term mechanism for the provision of primary regulating response.

B.2.3 Other comments on options set out in the draft report

This section sets out stakeholders' views on other options that were explored in the draft report for the provision of primary regulating response.

Stakeholder response

In addition to option A and option F, stakeholders also provided feedback on the other options for the provision of primary regulating response that were set out in the draft report. Below is a summary of this feedback.

Option B - Narrowing of trigger settings for the existing contingency services

Under this option, the trigger points for some or all of the existing contingency services would be narrowed through changes to the frequency operating standard and/or the Market ancillary service specification.[157]

A number of stakeholders agreed that this option was not appropriate for addressing the frequency performance issues in the NEM.[158] Stakeholders raised the following issues in relation to this option:

- Substantial changes to the frequency operating standard and the market ancillary service specification would be required
- Interfering with the operation of contingency services may place the power system at risk
- Sufficient amounts of continuous primary frequency response are unlikely to be delivered
- As the contingency FCAS arrangements are working well, it would be inappropriate to interfere with them in order to deal with an issue of frequency control in the NOFB.

Meridian Energy indicated this option is its preferred option.[159] In its submission to the issues paper Meridian Energy noted that this option was technology neutral and would allow market forces to determine the appropriate investment in contingency FCAS capability.[160]

Option C – The mandatory provision of a primary regulating response

A mandatory requirement could be placed on market participants for them to provide a primary regulating response.

157 See clause 3.11.2 of the NER. The fast, slow and delayed services are commonly referred to as contingency services. Currently the trigger settings for these services are defined by AEMO through the market ancillary service specification with reference to the normal operating frequency band which is defined in the frequency operating standard as 49.85 Hz - 50.15 Hz.

158 Submissions to the draft report: AEMO, p. 8; ENGIE, p. 3, Hydro Tasmania, p. 2.

159 Meridian Energy, submission to the draft report, p. 2.

160 Meridian Energy, submission to the issues paper, pp. 6-7.

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).A number of stakeholders considered that this option was not appropriate for addressing the frequency performance issues in the NEM.[161]

The Generator Group argued that the mandatory provision of primary regulating response is not likely to lead to efficient investment in electricity infrastructure in the long term interests of consumers and is therefore not likely to satisfy the National Electricity Objective.[162] In addition, the Generator Group referred to the market design principles set out in clause 3.1.4 of the NER, part 6 of which states that:[163]

> "...market ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis. Where dynamic determination is not practicable, competitive commercial contracts between AEMO and service providers should be used in preference to bilaterally negotiated arrangements."

Option D - Procurement of response and headroom via contracts

The contract procurement of primary regulating services would involve the specification of performance characteristics and the required quantity of primary frequency response by AEMO. These services would then be procured on a periodic contract basis by AEMO or potentially a TNSP as is the case for other non-market ancillary services such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS).

ENGIE and Fluence submitted that a contract procurement mechanism may be a suitable as an interim solution to the provision of primary regulating response while a longer term explicit market mechanism is under development.[164]

S&C Electric Company suggested that, "a mandatory contracting requirement should be placed on generators to deliver frequency response, both inertia and primary response (two different things)". S&C Electric Company qualified "that the mandated requirement should be remunerated".[165]

S&C Electric Company considered that all connected generators should have the capability to deliver a primary frequency response and to provide AEMO with an offer for the provision of primary frequency response. AEMO would select the mix of providers that deliver the most cost effective provision of primary frequency control. S&C Electric Company referenced the UK National Grid Mandatory Frequency Response market arrangements as an example of this form of contract procurement model.[166]

161 Submissions to the draft report: AEC, p. 2; ARENA, p. 2; ENGIE, p. 4; Generator group, pp. 57-59; Snowy Hydro, p. 6.

162 Generator Group, submission to the draft report, pp. 56-57.

163 See clause 3.1.4(6) of the NER.

164 Submissions to the draft report: ENGIE, p.4; Fluence, p. 2.

165 S&C Electric Company, submission to the draft report, p. 1.

166 S&C Electric Company, submission to the draft report, p. 7.

Option E - Development of new markets for primary regulating response

A large number of stakeholders supported the implementation of an explicit procurement mechanism for primary frequency response within the normal operating frequency band based on competitive market principles.[167] Stakeholders suggested a number of different ways for how such a procurement mechanism may operate including:

- Some stakeholders expressed support for the creation of a new market ancillary service, administered in the same way as the existing market ancillary services. Such a service would involve central procurement by AEMO on a periodic basis with competitive bids by registered providers and automated central dispatch. Submissions from ENGIE, AEC, Origin, ERM Power, Snowy Hydro, the Generator Group and AEMO all indicated support for some kind of central procurement of a primary regulating service.[168]

The Generator Group propose the specification of new centrally procured primary NOFB market ancillary services combined with a performance based 'causer pays' cost allocation mechanism based on frequency measurements and generator performance. This cost allocation mechanism would charge or pay generators based on whether their operational performance contributed to frequency deviations or helped correct them.[169]

- IES Advisory and CS Energy expressed support for a deviation pricing mechanism to reward participant deviations that help to manage frequency and penalise participant deviation that contribute to frequency deviations.[170] This concept involves a price function that establishes a value for frequency response on a periodic basis which is combined with a measurement of market participant performance. Under this model there is no central procurer of the primary regulating service. Instead, market participants are guided by the frequency deviation price function to decide how to operate their plant in relation to the provision of primary regulating response.

IES Advisory was of the view that a deviations model could be extended to cover contingency FCAS. It noted that:[171]

> "A deviations market in primary regulation would be a good way to trial the deviations market concept, although we believe the concept should be researched and demonstrated for wider application at the same time."

Commission analysis

The Commission recognises the benefits of working towards the development and implementation of an efficient and effective procurement mechanism as a long term solution to the provision of sufficient primary frequency control within the NOFB. However, the Commission also recognises that if an urgent and immediate need for additional

167 Submissions to the draft report: AGL, p. 1.; AEC, p. 2; ERM Power, p. 3; ENGIE, p. 4; Fluence, p. 2; Generator group, pp. viii, ix, 59, 61-62; Lyon Group, p. 2; Origin Energy, p. 2; Snowy Hydro, pp. 2,3,7.

168 Submissions to the draft report: AEC, p. 2; AEMO, p. 7; ERM power, p. 4; Generator group, p.59; Snowy Hydro, pp. 2,3,7.

169 Generator group, submission to the draft report, pp. 80-81.

170 Submissions to the draft report: CS Energy, p. 10; IES Advisory, pp. 1-4.

171 IES Advisory, submission to the draft report, p. 2.

measures is demonstrated, then an interim policy solution may be developed to address this need in the short term. However, the Commission considers that such interim measures should align with and not detract from the development of an efficient and effective long term solution.

This approach was supported by a number of stakeholders who cautioned against implementing a change to the frequency control arrangements as a “quick fix” without clearly establishing an urgent need for such a fix, understanding the likely impacts of such a change, and setting out the process and timeline for the development of a long term solution.[172]

In line with this, the final report for the frequency control frameworks review focuses on a work plan for the investigation of the system needs, including in relation to frequency control during normal operation and the development of a long term policy solution to address the identified technical needs.

The remainder of this section sets out the Commission’s response to stakeholder feedback in relation to the remaining options set out in the draft report, including whether it may be appropriate to consider these options further as interim or long term solutions to address the degradation of frequency control during normal operation.

Option B - Narrowing of trigger settings for the existing contingency services

The AEMC notes the support by Meridian Energy for Option B. However, the Commission agrees with the majority of stakeholder feedback that this option does not represent a preferred approach to the provision of primary frequency response.

As set out in the draft report, option B represents a fundamental change to the approach to frequency control in the NEM and may increase the risks associated with managing contingency events. Furthermore, based on AEMO advice, the Commission considers that the characteristics of a primary regulating response are different to that of a contingency response. A primary regulating response must be available to be continuously utilised to manage the normal fluctuations of supply and demand in the power system. In contrast, a contingency response is utilised only occasionally in the event of the failure of power system equipment, which allows for the provision of this type of response by temporarily depletable resources, such as those that draw down on stored boiler steam pressure.

The Commission is of the view that the appropriate procurement mechanism for primary regulating response should not rely on the utilisation of contingency services to perform the regulating function.

Option C - The mandatory provision of a primary regulating response

The Commission shares the concerns of stakeholders that a mandatory requirement for certain market participants to provide primary regulating services is likely to be an inflexible mechanism that does not allow for innovation in the delivery of these ancillary services and the delivery of services at lowest cost. Similarly, the Commission shares the

172 Submissions to the draft report: AEC, p. 1; Engineers Australia, p. 7; ENGIE, p. 1.

view set out by the Generator Group that a mandatory requirement for the provision of primary regulating services would be contrary to the market design principles set out in clause 3.1.4 of the NER.

At this time, the Commission is not aware of any evidence that would justify the consideration of a mandatory requirement as a long term measure for the provision of primary regulating services. However, the Commission recognises that should a clear system need be demonstrated, the Commission may consider whether a mandatory requirement to provide primary regulating service should be implemented as an effective short term interim measure.

Option D - Procurement of response and headroom via contracts

The Commission notes that the S&C Electric Company indicated its support for a mandatory capability to be able to provide primary frequency control along with a requirement to submit bids to a central procurement process for enablement and remuneration. S&C Electric Company suggested that the mandatory frequency response arrangements used in the UK national grid provide a practical example of such a mechanism.by National Grid. The Commission prefers to characterise this type of policy mechanism as a competitive procurement mechanism with mandatory participation as opposed to a mandatory service provision.

The Commission considers that a contract procurement model may be appropriate as an interim measure, if the need for such an interim measure arises.

One advantage of an interim contracting approach is that it would clearly define a volume of primary frequency response to be procured and would thereby provide a high degree of confidence that the required frequency response would be available.

However, there are potential disadvantages to a contracting approach for procurement of primary regulating services. For example, it may not be easy to quantify the system security risk that is posed by the observed degradation in frequency performance during normal operation. As such, it may be difficult to accurately determine the efficient volume of primary regulating response to procure, leading to a substantial risk of under- or over-procurement.

The potential role of interim policy measures is discussed further in Appendix A.

Option E - Development of new markets for primary regulating response

Stakeholder submissions generally supported further development of a new market based procurement mechanism for primary regulating response as a long term solution to the observed degradation of frequency performance during normal operation. The Commission agrees that an explicit market based procurement mechanism for primary regulating services has the potential to be a flexible, efficient and effective mechanism to support frequency control during normal operation.

Therefore, the Commission has investigated a range of potential market based mechanisms for the provision of primary regulating services. The results of these investigations are set out in Appendix A and will be further considered through the frequency control work plan discussed in Chapter 4 of this report.

Conclusion and approach

The Commission considers that frequency control frameworks should include incentives that result in sufficient primary frequency response to support good frequency performance and the secure operation of the power system.

Based on stakeholder feedback the Commission considers that there is no further need to investigate Option B (narrowing the trigger settings for contingency FCAS) or Option C (mandatory provision of primary regulating response) at this time.

In response to broad stakeholder support, the Commission proposes that a new market based procurement approach (Option E) be further considered as a potential long term procurement method for primary regulating response. Appendix A includes the Commission’s analysis of a range of potential market based procurement mechanisms.

C FREQUENCY MONITORING AND REPORTING, AND FORECASTING

In the draft report published for this review in March 2018, the Commission made the following conclusions:

- There is a lack of transparency regarding the frequency performance of the power system under normal operating conditions.
- There is a lack of transparency regarding the general performance of FCAS markets.
- Improvements to AEMO's supply and demand forecasting arrangements may help to drive better frequency outcomes.

This chapter sets out:

- the recommendations made by the Commission in the draft report to address each of the above issues
- a summary of stakeholder views on those recommendations, based on submissions to the draft report
- the Commission's subsequent analysis, conclusions and final recommendations.

C.1 Frequency performance of the power system

C.1.1 Background

In the draft report, the Commission concluded that there is a lack of transparency regarding the frequency performance of the power system during normal operation. This is because the existing frequency monitoring and reporting requirements in the NER relate to individual events. Specifically, 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.[173] 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.[174] 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
- the number of exceedance events on a monthly basis for each of the bands in the frequency operating standard.

173 See clause 4.8.15(iii) of the NER.

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

The AEMO website also contains an archive of frequency and time error monitoring reports.[175] This includes monthly reports from January 2011 through to June 2013, quarterly reports from Q3 2013 through to Q3 2014, reports for each quarter of 2017 (published in March 2018) and a report for Q1 2018. NEMMCO[176] published monthly frequency monitoring and time deviation reports from January 2004 through to January 2008. The most recent reports report on:

- whether the one per cent requirement of the frequency operating standard was met[177]
- events that resulted in excursions outside the normal operating frequency band
- events where the requirements of the frequency operating standard were not met (e.g. load or generation events)
- whether the requirements of the frequency operating standard with respect to accumulated time error were met.

As there is no regulatory requirement for AEMO to publish any of these reports, there is neither consistency in how often they are published nor formal consultation on what metrics are reported against. In the draft report the AEMC concluded that there is potential to improve these arrangements so that:

- market participants are more regularly informed about issues that affect power system security, and can make efficient investment and operational decisions
- the market can understand the impact of any changes to existing mechanisms, or the introduction of new mechanisms, to improve frequency performance during normal operation.

As such, the draft report recommended that a rule change request be submitted to amend the NER to require AEMO to monitor, and publish reports on, frequency outcomes with respect to the requirements of the frequency operating standard.

C.1.2 Stakeholder views

All stakeholders that commented on this recommendation in their submission to the draft report supported it.[178] This is consistent with feedback on the issues paper, which sought stakeholder views on whether there are any benefits to market participants of more regular reporting on frequency performance in the NEM.[179]

Stakeholders indicated that the benefits of reporting would (depending on the specific metrics being reported against) include:

175 Ibid.

176 The National Electricity Market Management Company Limited (NEMMCO) was the market operator from the commencement of the NEM until AEMO was formed in July 2009.

177 A requirement of the frequency operating standard is that frequency must not exceed the normal operating frequency band for more than one per cent of the time over a 30 day period (excluding contingency events).

178 Submissions on draft report: AGL, p. 4; AEC, p. 3; AEMO, p. 6; CEC, p. 4; ENGIE, p. 5; ERM Power, pp. 1,3; Fluence, p. 4; Hydro Tasmania, p. 3; Meridian Energy, p. 2; Tesla, p. 3.

179 Submissions on 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.

- giving generators a better understanding of how often and by how much the frequency is deviating
- understanding if the frequency operating standards were met or not met
- 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 under normal operating conditions
- allowing (if the reporting includes participant-specific data) each participant to identify the periods where they are not meeting their dispatch targets, and providing participants with the opportunity to interrogate AEMO's causer pays data and calculations.

In their submissions to the issues paper, Meridian Energy and Pacific Hydro considered that the costs of such a requirement would be negligible and would be outweighed by its potential benefits.

Stakeholder views diverged somewhat in relation to:

- the specific metrics that should be reported on
- how often the reports should be published
- how the obligation should be given effect and by whom.

Each of these issues is discussed in turn below.

Reporting metrics

The issues paper sought stakeholder views on what frequency metrics would be most valuable for AEMO to report on. Submissions proposed the following metrics:[180]

General metrics

- statistical analysis (histogram) of frequency
- 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
- time error trends
- rate of change of frequency
- area control error-based reporting[181]
- frequency nadirs.

180 Submissions on issues paper: EnergyAustralia, pp. 5-6; Hydro Tasmania, p. 9; Meridian Energy, p. 7; S&C Electric Company, p. 8; TasNetworks, p. 9. Fluence, submission on draft report, p. 4.

181 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 reports ACE-related metrics every four seconds in its causer pays datasets for the recovery of regulating FCAS costs.

Specific events or parameters

- fast Fourier transform analysis[182] 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.

Participant-level metrics

- 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
- how individual participants are responding (to frequency to ensure that the resources that are doing most of the work to correct deviations are being compensated).

Frequency of reporting

Stakeholders had differing views on how frequently the reporting should be conducted:[183]

- AEMO suggested that agreed frequency performance measures could be provided weekly, and detailed analysis could be provided quarterly.
- S&C Electric Company proposed monthly reporting.
- TasNetworks suggested quarterly reporting, unless AEMO is able to automate analysis and documentation to produce monthly reports without excessive effort.
- ERM Power supported quarterly reporting.
- The Clean Energy Council proposed monthly publication of key metrics and an annual report on trends.

Implementation of the obligation

AEMO was of the view that the NER should set out the required timing and high-level content for the reports, but that an AEMO guideline should set out the detailed content requirements.[184]

ERM Power proposed that the Reliability Panel consult on and issue guidelines on what AEMO should report on.[185]

C.1.3 Analysis and conclusions

The Commission agrees with stakeholders that the potential benefits of requiring AEMO to report on frequency outcomes include:

182 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.

183 Submissions on draft report: AEMO, p. 6; ERM Power, p. 3; Clean Energy Council, p. 4.

184 AEMO, submission on draft report, p. 6.

185 ERM Power, submission on draft report, p. 3.

- giving market participants a better understanding of whether the requirements of the frequency operating standard are being met
- alerting the market to the need for FCAS and providing information that will help market participants make investment decisions
- promoting transparency of the impact of any changes made to improve frequency performance under normal operating conditions.

While there are likely to be costs to AEMO of such a requirement, the Commission is of the view that these costs are likely to be outweighed by the benefits of transparency set out above.

In its submission to the draft report, AEMO noted that it has recently committed to monitor and report on NEM frequency performance on a quarterly basis.[186] AEMO reiterated this commitment in its presentation to the AEMC's technical working group on 22 May 2018. While the Commission is supportive of this initiative, it still considers there to be value in formalising this reporting through a regulatory requirement to provide certainty to market participants that such reporting will continue to occur. Members of the technical working group were also supportive of including an explicit reporting requirement in the NER.

A rule change would be required to give effect to a requirement for AEMO to report on frequency performance outcomes. The following sections set out more detail on how such a reporting obligation could be given effect. This detail is set out below.

Reporting metrics and frequency of reporting

The frequency operating standard, defined in the NER and determined by the Reliability Panel, sets out the range of allowable frequencies for the power system under different conditions, including normal operation and following contingency events. Specifically, the standard sets out the frequency containment, stabilisation and recovery requirements when the system is interconnected, when in an islanded state and during supply scarcity. These requirements inform how AEMO operates the power system, including through applying constraints to the dispatch of generation, or procuring ancillary services.

The frequency operating standard comprises two separate standards – one for the mainland NEM and one for Tasmania – to reflect the different physical and market characteristics of the two areas.

Based on stakeholder input in submissions and discussions with members of the technical working group, the Commission proposes that AEMO be required to report on frequency outcomes with respect to the requirements of the frequency operating standard. The requirements of the frequency operating standard for both the mainland and Tasmania are set out in section C.4.

The Commission proposes that this be done on a weekly basis. The metrics of the frequency operating standard are already clearly specified and understood by AEMO, the data should be relatively easy to collect, and the data set out in the report should not need to be

186 AEMO, submission on draft report, p. 6.

accompanied by any analysis. Rather, the reports could include a table that sets out each requirement in the frequency operating standard and a simple yes/no of whether that particular requirement was met. For example, if there was a network or generation event, the report should state whether AEMO managed to contain, stabilise and recover system frequency in accordance with the relevant requirements in the standard. AEMO's submission to the draft report indicates that this is achievable.

Stakeholders have also asked for greater transparency on the utilisation of regulating FCAS. Some consider that the deterioration of frequency performance under normal operating conditions could be addressed (either in whole or in part) if AEMO increased the quantity of regulating FCAS it enables, or set this quantity more dynamically according to the power system needs.[187] AEMO has indicated that, in some dispatch periods, it fully utilises the quantity of regulating FCAS enabled before the period is over. The Commission agrees with stakeholders that greater transparency of this will promote an understanding of whether the amount of regulating FCAS AEMO procures is appropriate or could be increased / set more dynamically. The Commission expects that this data would be relatively easy to collect, and therefore could be included in the proposed weekly reporting on whether the requirements of the frequency operating standard were met.

In addition, the Commission sees benefit in AEMO having a more explicit obligation to provide commentary on key trends or particular events with respect to system frequency. Having access to the raw data is beneficial, but AEMO's views and commentary on this data should help stakeholders understand:

- trends in frequency performance
- the effectiveness of the FCAS markets and AEMO's actions to restore system frequency following certain events
- the impact of any actions taken to improve frequency control outcomes.

The Commission therefore proposes that AEMO be required to publish quarterly reports providing its analysis of frequency trends and specific events (for example oscillatory events).[188] Members of the technical working group expressed their support for this approach. Again, AEMO's submission to the draft report indicates that this is achievable.

In both its submission to the issues paper and to the draft report, Snowy Hydro asked that any monitoring and reporting not be onerous on generators because they already undertake a significant amount of reporting. The Commission expects that AEMO would have most, if not all, of the information required to conduct the reporting proposed in this section. However, the rule change process should be able to elicit more specific views from AEMO and industry on whether this is the case.

In the Commission's view, the rule should also set out how soon after the reporting period has ended AEMO should publish the relevant reports. Ideally this would occur as soon as

187 This issue is discussed in more detail in Appendix A.

188 The rule change request would likely need to determine the threshold for what is considered to be a 'specific event' that should be reported on.

possible after the relevant reporting period has ended. There are two useful comparisons in the NER:

1. AEMO must publish on a daily basis certain information about the previous trading day.[189] This may be a useful guide for how soon after the relevant week AEMO should publish the proposed report on frequency outcomes with respect to the requirements of the frequency operating standard.
2. The AER must publish a report on significant variations between forecast and actual spot prices no later than four weeks after the end of each three month period.[190] This may be a useful guide for how soon after the relevant quarter AEMO should publish the proposed analysis of key trends and specific events, or the utilisation of regulating FCAS.

In determining how soon after the reporting period has ended AEMO should publish the relevant reports, the AEMC (through the rule change process) should consider:

- whether all necessary data is available to AEMO
- any costs to AEMO of requiring the reports to be published very soon after the period
- the extent to which data collection and reporting could be automated.

Implementation of the obligation

In submissions, AEMO and others suggested that a guideline be developed (either by AEMO or the Reliability Panel) to guide how AEMO gives effect to the reporting obligation.

In general, the AEMC's approach to reporting obligations is that the NER set out the legally binding obligation on the party – that is, the 'when', the 'what' and the 'to whom'. Often this is accompanied by some guidance or principles about what must be monitored, reported or published. A guideline would only exist to provide more information on what will be reported on and how, or to provide guidance on how the reporting party should go about meeting the obligation.

One benefit of having a guideline may be to provide flexibility to AEMO in how it gives effect to the obligation or the specific metrics that it reports against. Similarly, having AEMO develop a guideline gives it the ability to initiate changes to its content, rather than this being determined through a rule change process. However, AEMO guideline changes are still subject to stakeholder consultation.

In considering a rule change request to introduce the proposed reporting obligation, the value a guideline would add will need to be considered further and what its purpose would be. This would then inform who would be the most appropriate person to develop the guideline, if it is determined that one is needed. If the guideline is simply to set out more detail on how AEMO gives effect to the obligation (e.g. where it is published) then it would likely be more appropriate for AEMO to develop it. If there is a need for additional

189 See clause 3.13.8(a) of the NER.

190 See clause 3.13.7(b)(1) of the NER.

guidance to AEMO in how it meets the obligation, there could be a role for another party, such as the Reliability Panel.

Given it takes time to develop a guideline, it ought to have some benefit. At this stage, the Commission is of the view that requiring AEMO or the Reliability Panel to establish a guideline for how AEMO gives effect to the reporting requirement is an unnecessary step for a relatively straightforward obligation that could be set out in full in the NER. The NER obligation could be worded in such a way that requires AEMO to report on certain metrics as a minimum, but provides it with flexibility to report on other metrics if it wishes, or if stakeholders request it. However, the Commission does not yet have a clear position on this and therefore considers that it would be better addressed through the rule change process.

C.1.4 Recommendation

> **RECOMMENDATION 2: AEMO REPORTING ON FREQUENCY PERFORMANCE**
>
> That the AER submit a rule change request in Q3 2018 to amend the NER to require AEMO to publish:
>
> - weekly reports on frequency outcomes with respect to the requirements of the frequency operating standard
> - quarterly reports providing AEMO's analysis of key trends and specific events.

Proposed rule drafting to give effect to this recommendation is set out in the next section. The exact metrics to be reported against, and the required frequency of reporting, would be determined in consultation with stakeholders through a rule change process. For example, it may be more practical for AEMO to publish weekly reports on frequency outcomes with respect to the requirements of the frequency operating standard, and publish quarterly reports with further analysis on whether all the requirements of the frequency operating standard have been met.

C.1.5 Proposed rule drafting

4.8.16 Reporting by AEMO on frequency performance

(a) Each week, *AEMO* must prepare and publish on its website a report on:

1. whether or not the *frequency operating standards* set out in the *power system security standards* were achieved;
2. the quantity of *regulation servicesenabled* by *AEMO* in each region; and
3. the quantity of *regulation services* utilised by *AEMO* in each region;

in the preceding week.

(b) *AEMO* must prepare and publish on its website a report in respect of each three month period commencing on 1 January, 1 April, 1 July and 1 October in each year. The report:

1. must be published no later than 2 weeks after the end of each three month period, and

2. must include *AEMO's* detailed analysis of *power system frequency* control and trends for that three month period including without limitation:
    a. the effectiveness of any *market ancillary services* enabled and utilised by *AEMO* over the relevant period to control *power system frequency*;
    b. the impact of any actions taken by *AEMO* to improve *power system frequency* control outcomes;
    c. AEMO's assessment of the achievement of the *frequency operating standards* over that three month period, including its analysis of any occasions where the *frequency operating standards* were not met;
    d. rates of change of *frequency*;
    e. *area control error*; and
3. must include a summary of any reports prepared by AEMO on *reviewable operating incidents* which affected *frequency* over that three month period.

Chapter 10

New definition:

area control error (ACE)

When the *power system* is in a *satisfactory operating state*, the additional amount of electrical power (MW) required to be produced or consumed to correct a given *frequency* deviation.

C.2 FCAS market performance

C.2.1 Background

The draft report for the *Frequency control frameworks review* concluded that there is a lack of readily available information to participants about the general performance of FCAS markets.

This is because the existing FCAS market reporting requirements in the NER are primarily related to individual events. Specifically, the AER must report on incidences when FCAS prices at a regional reference node significantly exceed the spot price for energy and FCAS prices exceed $5,000/MWh for a number of trading intervals in that period.[191]

While the National Electricity Law (NEL) contains a requirement for the AER to monitor the performance of wholesale electricity markets, it is only required to report on the results of this monitoring at least once every two years.[192]

In the draft report the AEMC concluded that there is potential to improve these arrangements so that market participants:

- are more regularly informed about issues that affect system security and whether the FCAS markets are effective

191 See clause 3.13.7 of the NER.

192 This NEL obligation is discussed further in section [C.2.3].

- can make efficient investment and operational decisions.

As such, the draft report recommended that a rule change request be submitted to amend the NER to require 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.

C.2.2 Stakeholder views

All stakeholders that commented on this recommendation in the draft report supported it.[193]

Stakeholders indicated that the benefits of reporting would (depending on the specific metrics being reported against) include:

- understanding how much was spent on maintaining frequency within the normal operating frequency band (i.e. FCAS costs)
- giving stakeholders a sense of whether the FCAS markets are efficient and effective
- alerting the market to the need for FCAS and providing trend information that will assist potential investors with the timing of their investments.[194]

Some stakeholders put forward their views in relation to:

- the specific metrics that should be reported against
- the required frequency of the reporting
- how the obligation should be given effect and by whom.

Reporting metrics

Stakeholders had differing views on which FCAS market metrics should be reported against:[195]

- Hydro Tasmania suggested that the reports set out, for each category of FCAS, the amount of FCAS available versus the amount dispatched.
- S&C Electric submitted that the AER should monitor and report on the performance of individual FCAS providers, as well as the costs of inertia and FCAS.
- PIAC asked that we consider what monitoring and enforcement is required to identify where market concentration and other matters are resulting in prices that are above what is efficient.

Frequency of reporting

Stakeholders had differing views on how frequently the reporting should be conducted:[196]

- Meridian Energy suggested monthly reporting.

193 Submissions on draft report: AEC, p.3; AEMO, p.6; CEC, p.4; ENGIE, p.5; ERM Power, p.3; Hydro Tasmania, p.3; Meridian, p.2; Snowy Hydro, pp.8-9; Tesla, p.3.

194 Submissions on draft report: Clean Energy Council, p. 4; Snowy Hydro, p. 9.

195 Submissions on draft report: Hydro Tasmania, p. 3; S&C Electric, p. 7; PIAC, p. 5.

196 Submissions on draft report: AEMO, p. 6; Clean Energy Council, p. 4; Meridian Energy, p. 2; Snowy Hydro, p. 3.

- The Clean Energy Council proposed a monthly publication of key metrics and an annual report on market trends.
- AEMO suggested that the AER's reporting obligation align with the proposed AEMO reporting obligation.
- Snowy Hydro was of the view that the obligation should avoid duplication with what the AER is looking at in its wholesale market monitoring report.

Implementation of the obligation

There were few comments on this in submissions the draft report. Meridian Energy was of the view that the detailed obligations should be set out in procedures drafted and administered by the AER.[197]

C.2.3 Analysis and conclusions

As set out in Chapter 3, FCAS market dynamics have changed significantly in recent times with the entry of new providers, and changes in the types of technologies providing FCAS. The Commission agrees with stakeholders that the potential benefits of requiring the AER to report regularly on the performance of FCAS markets include:

- providing market participants and other interested stakeholders with an ongoing assessment of whether the FCAS markets are effective
- helping current and potential market participants make efficient investment and operational decisions
- giving market participants and other interested stakeholders an understanding of how much it costs to maintain good frequency control.

As mentioned in section C.2.1, the AER has an obligation under the NEL to monitor and report on the performance of wholesale electricity markets, which includes the FCAS markets. This obligation was introduced in 2016. Under Part 3, Division 1A of the NEL, the AER's monitoring functions are:

- to monitor and review on a regular and systematic basis the performance of wholesale electricity markets in accordance with the NEL and the NER
- to identify and analyse whether, in relation to a particular wholesale electricity market:
  - there is effective competition within the market
  - there are features of the market that may be detrimental to effective competition within the market
  - there are features of the market that may be impacting detrimentally on the efficient functioning of the market (and, if so, to assess the extent of the inefficiency)

197 Meridian Energy, submission on draft report, p. 2.

- other monitoring or analysing functions that relate to offers and prices (including forecast prices, actual prices and bidding) within any wholesale electricity market conferred on the AER by the Rules (i.e. the NER).[198]

The AER's wholesale market reporting functions include, among other things:

- to prepare, at least once every two years, a report on the results of the performance of the AER wholesale market monitoring functions
- to provide, as the AER thinks fit, advice on the results of the performance of the AER wholesale market monitoring functions to the Ministerial Council on Energy
- other reporting requirements that relate to the AER wholesale market monitoring functions conferred on the AER by the Rules.[199]

In March 2018 the AER published its statement of approach for these new functions. It also published a document outlining its focus for the 2018 report, which the AER is due to provide to the COAG Energy Council in December 2018.[200] According to that document, this year the AER will (among other things) "assess competition and efficiency in the FCAS market using similar measures as for the spot market. As well as monitoring FCAS for the NEM as a whole, we will also spotlight FCAS issues in South Australia due to South Australia's high reliance on renewables and the fact that it often forms a regional market." The AER's intention is to "examine the factors that may provide a competitive constraint on the behaviour of market participants as well as those factors that may facilitate the exercise of market power." These factors include market concentration and power, barriers to entry/exit and vertical integration.

The Commission is supportive of the AER's focus on competition in the FCAS markets for the 2018 review. Such reporting will likely provide transparency on FCAS market outcomes to achieve the objectives set out by the AEMC above. However, it is possible that FCAS markets will not be the focus of subsequent AER reviews. Further, the NEL only requires public reporting on the AER's wholesale market monitoring functions every two years. The AEMC therefore still sees benefit in there being more regular (i.e. quarterly) reporting on FCAS market outcomes, and stakeholders having certainty that this will occur.

While there are likely to be costs to AEMO and the AER of such a requirement, the Commission is of the view that these costs are likely to be outweighed by the benefits of transparency set out above. Further, there is potential for the AER to align the requirements of such an obligation with its existing obligation to monitor and report on wholesale markets under the NEL.

A rule change would be required to give effect to a requirement for the AER to report on FCAS market outcomes. The following sections set out more detail on how such a reporting obligation could be given effect. This detail is set out below. Proposed rule drafting to give effect to the final recommendation is set out in section C.2.5.

198 See section 18C(1) of the NEL.

199 See section 18C(2) of the NEL.

200 See: https://www.aer.gov.au/wholesale-markets/market-guidelines-reviews/wholesale-electricity-market-performance-monitoring-report-statement-of-approach

Reporting metrics and frequency of reporting

To achieve the benefits of reporting on FCAS market performance set out above, the Commission proposes that the AER be required to report quarterly on:

- the total costs of FCAS over the reporting period
- for each of the eight FCAS markets:
  - volumes (both enabled and utilised)
  - prices
  - number of participants
  - the technology types of those participants.

At the technical working group meeting on 22 May 2018, members supported the AER reporting quarterly on these metrics, using information provided to it by AEMO.

The Commission does not recommend that the AER be required to report on the performance of individual FCAS providers, as was proposed by S&C Electric Company. This is likely to be a level of granularity that is unnecessary for the reporting audience and would impose additional administrative burden on both AEMO and the AER to collect and report this information. In the Commission's view, the performance of individual FCAS providers is a matter best addressed by AEMO. In fact, AEMO is currently looking into the performance of individual FCAS providers to make sure that those who are enabled and paid for FCAS are actually delivering the service (which the AEMC understands has not always been the case to date).

Members of the technical working group were also asked for their input on the utility of the AER compiling these reports, or whether it would be preferable if AEMO made the raw data more readily and regularly available such that participants could run their own reports whenever it suited them. Members were generally of the view that the issue was not ease of access to the raw data, but rather having independent commentary on the effectiveness of the FCAS markets. The technical working group agreed that the AER was ideally placed to provide its analysis of whether the FCAS markets were well functioning and workably competitive. The Commission therefore proposes that any requirement for the AER to report on FCAS market outcomes also include:

- commentary on key trends
- an assessment of whether the FCAS markets are effective.

As explained above, the NEL already provides a framework for the AER for assessing whether there is "effective competition" in a wholesale electricity market. Specifically, section 18B of the NEL requires that the AER have regard to:

1. whether there are active competitors in the market and whether those competitors hold a reasonably sustainable position in the market (or whether there is merely the threat of competition in the market)
2. whether prices are determined on a long term basis by underlying costs rather than the existence of market power, even though a particular competitor may hold a substantial degree of market power from time to time

3. whether barriers to entry into the market are sufficiently low so that a substantial degree of market power may only be held by a particular competitor on a temporary basis
4. whether there is independent rivalry in all dimensions of the price, product or service offered in the market
5. any other matters that the AER considers relevant.[201]

The Commission is of the view that this framework provides sufficient guidance to the AER and stakeholders on how the AER's assessment of effective competition in FCAS markets could be put into effect.

In both its submission to the issues paper and its submission to the draft report, Snowy Hydro asked that any monitoring and reporting not be onerous on generators because they already undertake a significant amount of reporting. The Commission expects that AEMO would have most, if not all, of the information required to provide to the AER for the required reporting. The rule change process should be able to elicit views from stakeholders on whether this is the case.

In the Commission's view, the rule should also set out how soon after the reporting period has ended AER should publish the relevant report. Ideally this would occur as soon as possible after the relevant reporting period has ended, but would also depend on how quickly AEMO is able to provide the relevant data to the AER. As set out in section C.1.3, a useful comparison in the NER is the existing requirement for AEMO to publish a report on significant variations between forecast and actual spot prices no later than four weeks after the end of each three month period.[202]

In determining how soon after the reporting period has ended the AER should publish the relevant report, the AEMC (through the rule change process) should consider:

- whether all necessary data is available to AEMO and the AER
- any costs to AEMO and the AER of requiring the reports to be published very soon after the period
- the extent to which data collection and reporting could be automated.

Implementation of the obligation

Meridian Energy proposed that the detailed reporting obligations should be set out in procedures that are drafted and administered by the AER.

Section C1.1.3 of this report sets out the AEMC's general approach to whether reporting obligations should sit in the NER or in a guideline.

At this stage, the Commission is of the view that requiring the AER to develop a procedure or guideline for how it gives effect to the reporting requirement is an unnecessary step for a relatively straightforward obligation that could be set out in full in the NER. The NER obligation could be worded in such a way that requires the AER to report on certain metrics

201 See section 18B of the NEL.
202 See clause 3.13.7(b)(1) of the NER.

as a minimum, but provides it with flexibility to report on other metrics if it wishes, or if stakeholders request it. Given it takes time to develop a procedure/guideline, it ought to have some benefit. However, the Commission does not yet have a clear position on this and therefore considers that it would be better addressed through the rule change process.

C.2.4 Recommendation

RECOMMENDATION 3: AER REPORTING ON FCAS MARKET OUTCOMES

That the AER submit a rule change request in Q3 2018 to amend the NER to require the AER to report quarterly on the performance of FCAS markets, specifically:

- the total costs of FCAS
- volumes (both enabled and utilised), prices, number of participants for each of the eight FCAS markets and the technology types of those participants
- commentary on key trends
- an assessment of whether the FCAS markets are effective.

Proposed rule drafting to give effect to this recommendation is set out in the next section. The exact metrics to be reported against, and the required frequency of reporting, would be determined in consultation with stakeholders through a rule change process. For example, it may be more appropriate or beneficial for stakeholders if the AER conducted its assessment of whether the FCAS markets on an annual basis, rather than quarterly.

C.2.5 Proposed rule drafting

3.11.2A Reporting on market ancillary services markets

(a) The *AER* must prepare and *publish* a report in respect of each three month period commencing on 1 January, 1 April, 1 July and 1 October in each year. The report must:

1. be *published* no later than 4 weeks after the end of each three month period;
2. contain the following information in relation to each *market ancillary service* listed in clause 3.11.2(a) for that three month period:
    a. the total costs for the provision of that *market ancillary service* for each *region*;
    b. the total quantity of that *market ancillary serviceenabled* by *AEMO* in each *region;*
    c. the total quantity of that *market ancillary service* utilised by *AEMO* in each *region;*
    d. the average, lowest and highest *ancillary service price* for each region for that *market ancillary service;* and
    e. the number and types of *ancillary service providers;*
3. contain the *AER's* analysis of key trends in the *market ancillary servicemarkets* over that three month period; and
4. contain an assessment by the *AER* of the performance of the *market* for each of the *market ancillary services* listed in clause 3.11.2(a) over that three month period,

including in the AER's opinion, whether the *market* is functioning efficiently, and whether there is effective competition in the market.

C.3 Supply and demand forecasting

C.3.1 Background

Forecasting is an integral part of NEM operations. Accurate forecasts help AEMO manage the supply/demand balance and keep frequency within the requirements of the frequency operating standard. However, changing technology and behaviour in the power system is leading to increased variability and unpredictability of supply and demand, which makes 'good frequency performance' more difficult to achieve.

To balance supply and demand, and maintain frequency close to 50 Hz, AEMO dispatches scheduled generation to meet its forecast demand. The frequency impacts of variations in non-dispatchable capacity[203] that create imbalances in supply and demand within the dispatch interval are currently managed through the provision of regulating FCAS.

With continued growth in non-dispatchable capacity, the size and number of continuous minor supply demand imbalances is expected to grow. Sudden changes in output from non-dispatchable capacity within a dispatch interval can increase the level of uncertainty in the dispatch process, which may increase the amount of FCAS needed to maintain frequency within the requirements of the frequency operating standard.

Variations between supply and demand within the five minute dispatch interval are what drives the use of contingency and regulating FCAS and brings about system security (rather than reliability) concerns. AEMO uses a "neural network" model to forecast demand for dispatch (i.e. forecasts for 5 minutes in the future).

In the draft report, the AEMC concluded that improvements to the accuracy of supply/demand 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. Nevertheless, we acknowledged that forecasts will never be 100 per cent accurate, and 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. The AEMC therefore concluded that the objective should be to make dispatch demand forecasts as accurate as is efficient and use regulating FCAS to make up any difference. Submissions on the issues paper generally agreed with this conclusion.

The draft report did not make any draft recommendations in relation to forecasting, but rather noted that forecast accuracy, and ways to improve it, is being explored through the *Reliability frameworks review*, and that any final recommendations in this review will be informed by that work.

203 The term, 'non-dispatchable capacity' is used in this report 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.

C.3.2 Stakeholder views

There were very few comments on this aspect of the draft report.

The Group of Generators raised issues with AEMO's current forecasting arrangements. Specifically, it submitted that AEMO's neural network load forecast may not be optimal for variable load forecasting, and that its solar and wind generation forecasting systems are not optimally designed for forecasting the upcoming five minute dispatch interval.[204]

Others suggested ways in which forecasting could be improved:

- Satellite images and sky cameras can be used for short term solar generation forecasting, and machine learning approaches have produced promising results for wind generation forecasting.[205]
- Generator self-forecasting can improve short-term forecast accuracy.[206]
- Incentives to improve self-forecasting accuracy would likely be greater under the proposed enhanced causer pays regime.[207]

In its submission to the issues paper, the Clean Energy Council noted that a participant's contribution factors[208] for the recovery of regulating FCAS costs are calculated by comparing the measured generation of each wind farm against the aggregate forecast from Australian wind energy forecasting system (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 manage their contribution factors because there is a lack of transparency in 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 therefore supported participant self-forecasting for the coming immediate dispatch intervals (e.g. 5-15 minutes ahead) on the basis that it would enable participants to better manage risks, while also reducing forecasting error and demand for regulating FCAS.

Reliability frameworks review

The AEMC published a directions paper on the *Reliability frameworks review* in April 2018. The review is looking at forecasting issues through a reliability lens, with a focus on the

204 Group of Generators, submission on draft report, p. 51.

205 Submissions on draft report: Snowy Hydro, pp. 7-8; Generator Group, p. 51; ARENA, p. 3.

206 Submissions on draft report: ARENA, p. 3; S&C Electric Company, p. 2.

207 ARENA, submission on draft report, p. 3. The enhanced causer pays regime was one option proposed by the AEMC to address the recent deterioration of frequency control performance under normal operation. This is discussed further in [Appendix B].

208 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 Australian solar energy forecasting system (ASEFS) for solar generation.

AEMO's *Electricity Statement of Opportunities*, medium term projected assessment of system adequacy (PASA), short term PASA and 30-minute pre-dispatch forecasts. Among other things, the paper set out the AEMC's initial views on potential changes to the forecasting framework to reduce and diversify risks associated with the centralised forecast process, which include:

- greater reporting on the difference between forecasts and actuals
- enabling 'self-forecasting' by utility-scale wind and solar generators
- requiring retailers to forecast their own load and submit this to AEMO.

Submissions on the *Reliability frameworks review* directions paper closed on 18 May 2018. Largely, stakeholders:

- appreciated the need for demand forecast conservatism, but were concerned about the degree of over-forecasting
- supported greater transparency of forecast accuracy and AEMO's forecasting methodologies
- agreed that 'self-forecasting' is likely to improve forecast accuracy, but considered that the AEMC should wait for the AEMO/ARENA trial on this to conclude before proposing any rule changes
- did not support a requirement for retailers to forecast their own load, on the basis that it would be a significant change for an as yet undemonstrated benefit.

AEMO's submission agreed with the AEMC's conclusion that short-term forecasting[209] is likely to become increasingly challenging as a result of a tighter supply/demand balance and increased climatic variability. It noted the measures it is putting in place to refine its short term forecasting approach, including:

- moving toward risk-based and probabilistic forecasting
- using data science and machine learning to enhance forecasts
- improving weather forecasting and 'now-casting' (real time observations)
- using multiple service providers for weather, demand and generation forecasts
- enabling wind and solar generators, and VPPs, to submit self-forecasts
- redesigning the AEMO IT platform to facilitate new forecasting approaches
- investigating transmission connection point forecasting (i.e. bottom up forecasting).[210]

The AEMC published a final report on the *Reliability frameworks review* on 26 July 2018. Among other things, the report recommended a number of improvements to the existing arrangements for forecasting.

In relation to forecast accuracy, the AEMC concluded that more transparency around trends and drivers in forecasts should help energy market participants to make more efficient decisions, and therefore recommended that:

209 AEMO uses the terms 'short-term forecasting' and 'operational forecasting' to refer to the forecasting period ranging from five minutes to seven days ahead of real time.

210 AEMO, submission on directions paper, pp. 3-4. These comments are consistent with those in AEMO's Summer 2017-18 operations review, published May 2018.

- AEMO engage with industry through the Wholesale Consultative Forum on the provision of forecast deviation data and then provide this data
- a rule change request be submitted for the AER to:
    - consult on and prepare a guideline on forecast accuracy reporting
    - produce a quarterly report on the accuracy of the pre-dispatch, STPASA and MTPASA forecasts in accordance with the guideline.

In relation to forecast transparency, the AEMC concluded that the methodologies used for forecasting should be completely transparent, to the extent possible, to allow a full understanding of all inputs, and independent verification of the results. The final report recommended that a rule change request be submitted to require AEMO to consult on and prepare a new guideline that it will follow in developing and amending its forecasting methodologies.

In relation to self-forecasting by wind and solar generators, the AEMC agreed with stakeholders that it is appropriate to consider the results of the AEMO/ARENA trial before considering any regulatory change and recommended that:

- ARENA continue to fund projects that explore the potential for forecast improvements in the hours ahead of dispatch
- AEMO consider what functionality (and validation process) would be required for hours ahead self-forecasts, and self-forecasting by non-scheduled generators, and work towards providing this functionality through its trials.
- AEMC keep a “watching brief” on the ARENA trials in order to be able to use the learnings from these trials to inform any rule change requests that may be submitted to incorporate self-forecasting in the rules.

In relation to retailer self-forecasting, the AEMC concluded that implementing such a requirement at the current time is unlikely to result in more efficient market outcomes than the status quo, and recommended that issues associated with the visibility of distributed energy resources should be pursued through ongoing AEMC and AEMO projects, and other industry initiatives.

C.3.3 Analysis and conclusions

While the proposed improvements to forecasting arrangements above were considered in the context of reliability timeframes – i.e. longer term to pre-dispatch forecasts – any changes that improve the accuracy of forecasting for reliability purposes are likely to have flow on impacts for the supply/demand balance within a dispatch interval, and thus support better frequency control.

In the Commission’s view, there are three drivers of variations between supply and demand within a dispatch interval:

1. Unexpected loss of load or generation, e.g. due to a fault or unanticipated weather event.
2. Inability for generators/loads to comply with dispatch instructions.

3. Unexpected, large, coordinated operation of distributed energy resources (e.g. a virtual power plant).

The first driver is unlikely ever to be able to be entirely addressed through more accurate supply/demand forecasting, given that these events are generally unpredictable. Regulating and contingency FCAS will therefore always be needed in one form or another to maintain the supply/demand balance and power system security in light of these unexpected events. Chapter 3 and Appendix A of this report set out the Commission's views on broader, longer-term changes to the existing FCAS market frameworks to better reflect the needs and capabilities of the power system as it changes.

The second driver may be addressed through better forecasting if AEMO can determine patterns in over/under-compliance with dispatch instructions. However, it is likely better addressed through compliance and enforcement measures, and proper testing of the capability of generator/load equipment to meet dispatch targets. It may also be addressed if non-scheduled and semi-scheduled generators were required or able to forecast their own expected generation and submit those forecasts to AEMO, thereby reducing demand forecasting errors and demand for regulating FCAS. As set out above, the *Reliability Frameworks review* explored participant self-forecasting and concluded that the results of the AEMO/ARENA trial on this matter should be assessed before any regulatory change is considered.

The third driver may increasingly become an issue as more and more distributed energy resources are connected and aggregated for participation in wholesale markets. A lack of awareness of where these resources are and how they operate may increase demand forecasting errors and thereby increase the enablement and use of regulating FCAS. Large, sudden operation of a virtual power plant, for example as a coordinated response to NEM price spikes or troughs, may exceed regulating FCAS capability and trigger the use of contingency FCAS if this movement causes frequency to move outside the normal operating frequency band. AEMO and the AEMC are undertaking a range of projects to address this and broader issues associated with the visibility and operation of distributed energy resources and virtual power plants, including those set out below.

- On 26 June 2018 the AEMC made a draft rule to establish a register of distributed energy resources in the NEM, including small-scale storage systems and rooftop solar PV. The intention of the register is to give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system.[211]
- In 2015 the AEMC made a rule that requires registered participants to provide information on demand side participation to AEMO. This has now been implemented through the creation of AEMO's demand side participation portal. The data provided through the portal is expected to provide greater visibility of distributed energy resources that are responsive to price signals. AEMO is required to take this information into account when developing and using its load forecasts.[212]

211 See: https://www.aemc.gov.au/news-centre/media-releases/draft-rule-set-national-register-small-scale-batteries-and-other
212 https://www.aemc.gov.au/rule-changes/improving-demand-side-participation-information-pr

- In June 2018 AEMO and Energy Networks Australia published a consultation paper on their *Open Energy Networks* project, which is exploring options to ‘optimise’ the operation of distributed energy resources to help ensure quality and reliability of supply, and lower household bills.[213]
- The AEMC is working with AEMO to develop a joint work program on distributed energy resources, with the objective of better coordinating the various areas of work that both bodies are undertaking on related issues. This includes joint consideration of the broader technical and regulatory challenges associated with virtual power plants, including consideration of whether they are accurately captured by the NER’s existing registration categories and the MW threshold at which they should be scheduled.

In light of this work, and the other initiatives being undertaken by AEMO to improve its forecasting, this report does not make any recommendations to address forecasting issues. The AEMC will continue its assessment of forecasting issues through its ongoing system security and reliability work program.

C.4 Requirements of the frequency operating standard

The tables below summarise the frequency operating standards for the mainland and for Tasmania. This information is provided as a reference for section C.1 of this appendix.

Table C.1: NEM mainland frequency operating standards - interconnected system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error	15 seconds	N/A	N/A
No contingency event or load event	49.75 to 50.25 Hz, 49.85 to 50.15 Hz - 99 per cent of the time	49.85 to 50.15 Hz within 5 minutes	
Generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Protected event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz (reasonable	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

213 https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
	endeavours)	(reasonable endeavours)	(reasonable endeavours)

Table C.2: NEM mainland frequency operating standards - islanded system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
The separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Protected event	47 to 52 Hz	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 52 Hz (reasonable endeavours)	49 to 51 Hz within 2 minutes (reasonable endeavours)	49.5 to 50.5 Hz within 10 minutes (reasonable endeavours)

Table C.3: NEM mainland frequency operating standards - during supply scarcity

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	48 to 52 Hz (Queensland and South Australia) 48.5 to 52 Hz (NSW and Victoria)	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Protected event	47 to 52 Hz	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple	47 to 52 Hz	49 to 51 Hz within	49.5 to 50.5 Hz within 10

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
contingency event or separation event	(reasonable endeavours)	2 minutes (reasonable endeavours)	minutes (reasonable endeavours)

Table C.4: Tasmanian frequency operating standards - interconnected system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error	15 seconds		
No contingency event or load event	49.75 to 50.25 Hz 49.85 to 50.15 Hz, 99 per cent of the time	49.85 to 50.15 Hz within 5 minutes	
Load event	48 to 52 Hz	49.85 to 50.15 Hz within 10 minutes	
Generation event	48 to 52 Hz	49.85 to 50.15 Hz within 10 minutes	
Network event	48 to 52 Hz	49.85 to 50.15 Hz within 10 minutes	
Separation event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Protected event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 55 Hz (reasonable endeavours)	48 to 52 Hz within 2 minutes (reasonable endeavours)	49.85 to 50.15 Hz within 10 minutes (reasonable endeavours)

Table C.5: Tasmanian frequency operating standards - islanded system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event or load event	49 to 51 Hz		
Load or generation event	48 to 52 Hz	49 to 51 Hz within 10 minutes	
Network event	48 to 52 Hz	49 to 51 Hz within 10 minutes	
Separation event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49 to 51 Hz within 10 minutes
Protected event	47 to 55 Hz	48 to 52 Hz within	49.85 to 50.15 Hz within

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
		2 minutes	10 minutes
Multiple contingency event	47 to 55 Hz (reasonable endeavours)	48 to 52 Hz within 2 minutes (reasonable endeavours)	49 to 51 Hz within 10 minutes (reasonable endeavours)

D PARTICIPATION OF DISTRIBUTED ENERGY RESOURCES IN SYSTEM SECURITY FRAMEWORKS

In the draft report published for this review in March 2018, the Commission set out the following conclusions:

- 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).
- 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.
- 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 for distributed energy resources to provide system security services.

This appendix sets out:

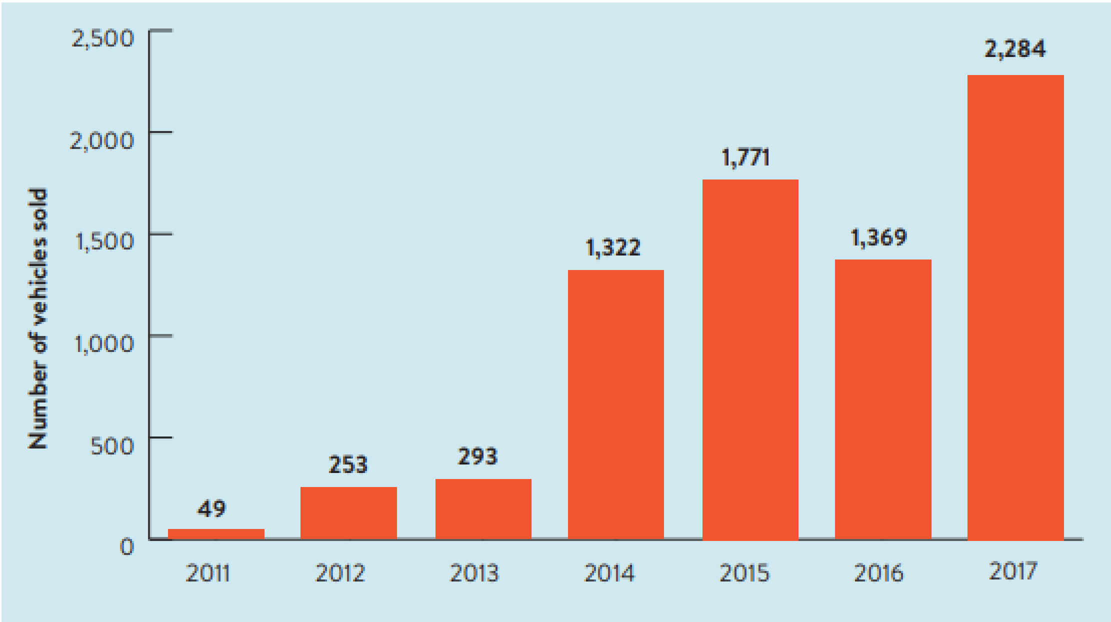
- the recommendations made by the Commission in the draft report to address each of the above issues
- a summary of stakeholder views on those recommendations, based on submissions to the draft report
- the Commission’s subsequent analysis, conclusions and final recommendations.

D.1 Overview of work stream

In addition to the withdrawal of large synchronous generators, there has been a rapid and ongoing uptake of distributed energy resources.

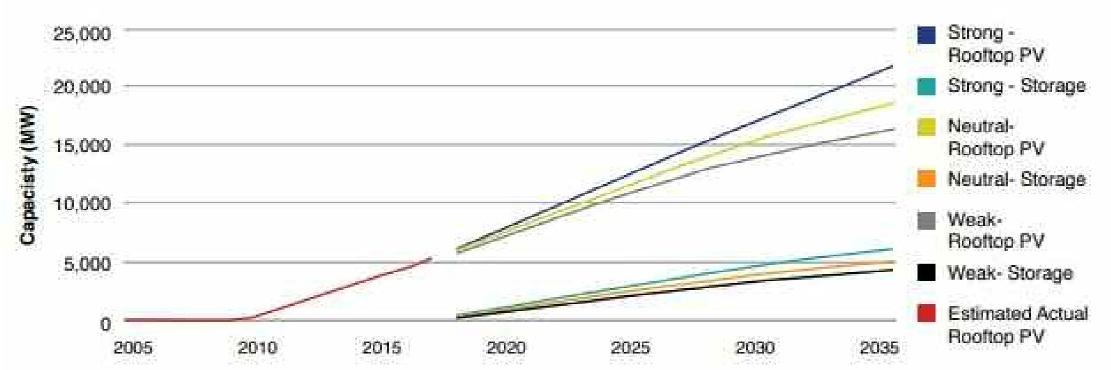
This has predominantly consisted of distributed solar photovoltaic (PV) systems, but is increasingly including other technologies such as batteries and electric vehicles (see Figure D.1 and Figure D.2). These technologies are changing the way in which consumers draw electricity from, and export electricity to, the broader power system. Distributed energy resources bring with them challenges and opportunities for power system security.

Figure D.1: Uptake of electric vehicles



Source: ClimateWorks Australia, *The state of electric vehicles in Australia*, Second report: Driving momentum in electric mobility, p. 6, June 2018. Information originally sourced from V-Facts.
Note: These number include estimates of Tesla sales. Tesla does not publicly release its sales figures and has not supplied these figures.

Figure D.2: Uptake of solar PV and storage



Source: AEMO/Energy Networks Australia, *Open Energy Networks*, consultation paper, p. 10, June 2018.
Note: This is a projection of installed capacity of rooftop PV and distributed energy storage in the NEM.

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 and with stakeholder input, we 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 frameworks in the NER that provide for the aggregation of distributed energy resources, one does not accommodate the aggregation of small generating units for the purpose of providing market ancillary services, and the other is unclear on whether aggregated small generating units can be used to provide 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 by Small Generation Aggregators to offer market ancillary services. It is also not clearly set out in the NER nor the MASS that small generating units can be enabled by Market Ancillary Service Providers as a market ancillary load.
- The requirement for market ancillary service offers to be made in whole megawatts (MWs). This is a requirement currently set out in the NER. 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 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. These impacts are neither transparent nor well understood.

The draft report made recommendations regarding each of the above. Following the publication of the draft report we have engaged with stakeholders and received written stakeholder submissions.

D.1.1 Recent developments in distributed energy resource participation in the NEM

A number of recent developments have demonstrated a growing interest in aggregating distributed energy resources to provide services at a wholesale level. These are summarised in Box 4.

BOX 4: RECENT DEVELOPMENTS IN AGGREGATION OF DISTRIBUTED ENERGY RESOURCES

AGL virtual power plant

AGL, with support from ARENA, is developing a virtual power plant in South Australia with a 5 MW capacity. It will consist of 1,000 distributed energy storage systems. The objective of the project is to demonstrate the role of distributed energy storage in enabling higher penetrations of variable renewable energy, and accessing a number of value streams, including the wholesale and FCAS markets.

Simply Energy virtual power plant

On 28 March 2018, ARENA announced that it was providing funding for a second virtual power plant to be built in South Australia. The virtual power plant will have a capacity of 8MW: 6MW of residential electricity storage and 2MW of commercial demand response. The capacity of the virtual power plant will be controlled to provide benefits to the consumers, energy retailers and the local network.

The project is working with South Australia Power Networks (SAPN) to provide greater visibility of the aggregated distributed energy resources as well using these resources to address local network constraints and manage demand.

The virtual power plant will also utilise Greensync's deX platform.

Energy Networks Australia submission

Energy Networks Australia noted that a number of its members had already conducted trials to better understand and manage the challenges associated with aggregated distributed energy resources.

For example, SAPN recently trialled a virtual power plant consisting of 100 customers receiving subsidised battery storage resulting in 300kW of capacity. The trial sought to understand how the benefits of the storage could be shared with the customers and the network to assist with deferring capital investments.

Market Ancillary Service Providers

There are currently two registered Market Ancillary Service Providers in the NEM: EnerNOC and Hydro Tasmania. Market Ancillary Service Providers can aggregate loads for participation in FCAS markets.

ARENA funding for distributed energy resources projects

ARENA announced a round of funding for projects relating to distributed energy resources. These funding rounds sought projects that would:

- demonstrate how distribution networks (and power systems more broadly) can improve their ability to accommodate increasing levels of distributed energy resources

- allow market operators to maintain power system security and reliability with high penetrations of distributed energy resources
- increase the visibility, predictability or control of distributed energy resources for AEMO, NSPs and to improve the connection process
- identify locational and temporal incentives that can support higher levels of distributed energy resources to optimise overall power system performance
- compare control strategies for distributed energy resources in terms of their benefit for consumers and contribution to overall power system performance
- identify factors that influence the ability to coordinate aggregations of distributed energy resources.

The outcomes from this funding round are expected to be announced in late 2018.

Source: AGL, *Virtual power plant in South Australia - Stage 1 milestone report*, July 2017; ARENA, 'Simply Energy to build 8MW virtual power plant in Adelaide', Media release, March 2018; For more information on deX, see: https://greensync.com/solutions/dex/; Energy Networks Australia, submission to draft report, p. 1.

Concurrent with the increasing uptake of distributed energy resources, a number of large transmission-connected synchronous generators have retired, and a number more are expected to do so. 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 provide these services. This need could become particularly acute in regions where the output of distributed energy resources is reducing minimum operational demand,[214] which consequently reduces the amount of generation provided through central dispatch from conventional sources.

This ongoing transformation of the power system provides the context for a review of the regulatory frameworks governing the provision of system security services. As the uptake of distributed energy resources continues, particularly in an aggregated manner, it is important that system security frameworks remain fit for purpose. These frameworks should facilitate distributed energy resources contributing to power system security where they are able to do so.

D.2 Role for distributed energy resources in system security frameworks

D.2.1 Introduction

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 will have to evolve over time. This has limited the extent to which frameworks for the provision of system security services by distributed energy resources can be properly assessed and formulated through this review.

214 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.

Nevertheless, 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 distributed energy resources play an increasing role in system security frameworks, there will likely be new challenges arising that will require further consideration of the regulatory framework.

This review has focused on some aspects of the existing regulatory frameworks that may be inefficiently limiting the ability of distributed energy resources to participate in FCAS markets. A more holistic, forward-looking review of the frameworks for distributed energy resources in future may help us better understand the broader challenges associated with their participation in energy markets.

There are two significant drivers for considering the role of distributed energy resources in system security frameworks:

1. As system security services have traditionally been provided by large, transmission-connected generators, the existing regulatory framework may not enable these services being provided by distributed energy resources. This review provides an opportunity to consider whether these frameworks present a barrier to distributed energy resources providing system security services and, if so, whether those barriers are inefficient.
2. The opportunity to establish frameworks that allow for distributed energy resource participation, where appropriate, before this occurs on a large scale. Consequently, as aggregator business models develop and investments in distributed energy resources are undertaken, these decisions should increasingly be able to factor in the opportunity to participate in system security frameworks.

The effect of opening system security frameworks to distributed energy resources has been demonstrated to some extent through the participation of aggregated demand response in FCAS markets. The participation of this aggregated demand response arose from rule changes allowing third parties (i.e. Market Ancillary Service Providers) to aggregate loads for which they are not the retailer. This has increased the number of participants offering contingency FCAS services.

Facilitating the entry of new participants into these markets would further increase 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. This has been demonstrated by the impact of new entrants to FCAS markets in the NEM, as shown in Box 5. It should also provide investment and operational signals to the owners and operators of distributed energy resources to make decisions that can contribute to power system security and provide value for the required services.

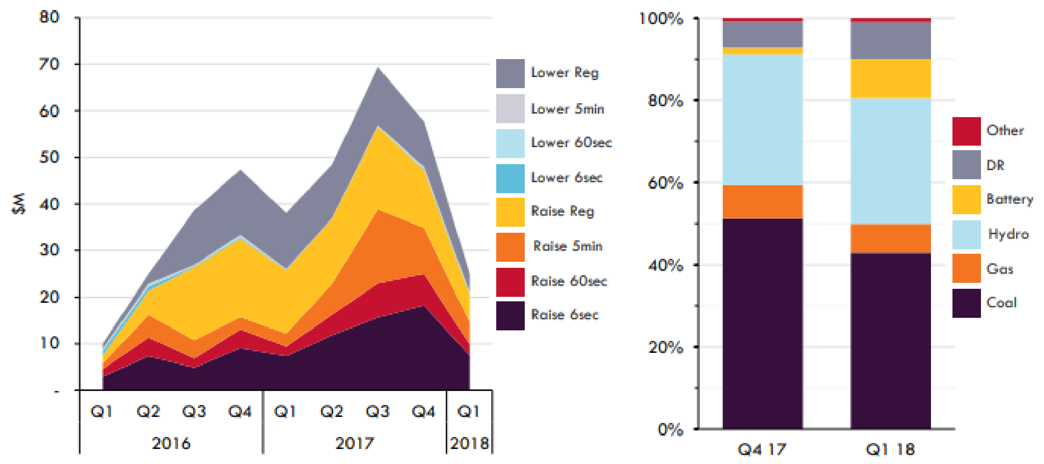
BOX 5: NEW PARTICIPANTS IN FCAS MARKETS

FCAS costs fell from almost $60m in Q4 2017 to $25m in Q1 2018.

AEMO's Quarterly energy dynamics report found that this was due, in part, to the additional supply from two new participants: the Hornsdale Power Reserve and EnerNOC.

Figure D.3 shows the falling costs of FCAS and the changing mix of providers of raise FCAS by fuel type.

Figure D.3: Quarterly FCAS cost by service and raise FCAS supply by fuel type



Source: AEMO, *Source: Quarterly Energy Dynamics*Source: , Q1 2018, p. 13, May 2018.

D.2.2 Services that can be provided by distributed energy resources

System security services broadly refer to those non-energy services that are used to manage power system security. These services maintain key technical characteristics of the power system, including by helping to meet system standards for frequency, voltage, current and stability.

Generally, system security services can be provided by a change in active or reactive power output or consumption. For example, the frequency operating standard is met through the procurement of sources of active power that are able to increase or decrease active power output. Distributed energy resources 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.

Other system security services that could be provided by distributed energy resources include:

- reactive power output or consumption to provide voltage support
- inertia or inertia-related services to either participate in a future ancillary service market or procured as a network service by an NSP

- system strength services to either participate in a future ancillary service market procured as a network service by an NSP.

These services may be able to be provided at an individual level but are more likely to be provided through aggregation. By aggregating a large number of distributed energy resources and controlling service provision, distributed energy resources would be able to have a more material contribution to maintaining power system security.

D.2.3 Stakeholder submissions on the role of distributed energy resources and its impact of system security

Consistent with submissions to the issues paper, stakeholders' submission to the draft report were supportive of this work stream's objective.

Tiko Energy Solutions[215] supported the review's objective in relation to the role for distributed energy resource participation. However, it considered the review lacked a clear statement on the role for demand response in providing system security services.[216]

Energy Networks Australia considered that changes to FCAS frameworks to permit distributed energy resource participation would go some way to addressing the decline in frequency control performance.[217]

AEMO noted that to be able to maximise the contribution from distributed energy resources at times of high potential, it is likely to need to also access system security services from distributed energy resources.[218] AEMO cautioned that unlocking the potential of distributed energy resources for FCAS may inadvertently create other barriers to broader participation. It suggested consideration should also be given to the broader impacts and opportunities with regard to power system security and reliability.[219]

AEMO highlighted that it was currently undertaking work to understand the impact of distributed energy resources on power system security. This work was indicating that distributed energy resources have an unpredictable response to power system disturbances.[220] AEMO was of the view that system security frameworks should incorporate measures that recognise and address how distributed energy resources may increase the need for system security services.[221]

D.2.4 Impact of distributed energy resources on system security

The Commission notes that the growing uptake of distributed energy resources poses challenges for power system security. It is important that AEMO, in order to maintain the safe, secure and reliable operation of the NEM, look at issues associated with the uptake of distributed energy resources. However, this is not the focus of this review. Both AEMO and

215 Tiko Energy Solutions is a demand response aggregator that operate across Europe. They have typically aggregated smaller loads.

216 Tiko Energy Solutions, submission to draft report, pp. 5-6.

217 Energy Networks Australia, submission to draft report, p. 1.

218 AEMO, submission to draft report, p. 9.

219 Ibid.

220 Ibid, p. 12.

221 AEMO, submission to draft report, p. 9.

NSPs have programs of work underway to understand and manage these challenges. This includes a joint consultation paper released by AEMO and Energy Networks Australia considering how to transition to a grid that allows for better integration of distributed energy resources.[222] The Commission has worked with AEMO and Energy Networks Australia to incorporate the outcomes of that work within the analysis and proposed recommendations for 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, in the draft report the Commission acknowledged that the aggregated provision of system security services using distributed energy resources may have consequential impacts on networks and broader system security.

In the draft report the Commission acknowledged that there are likely to be new challenges encountered by distributed energy resources in regulatory frameworks as participation grows. These challenges are likely to be complex and require further consideration than has been given through this review. Some of the challenges have been acknowledged in our *Distribution market model* project, this review and in stakeholder submissions.

D.3 Aggregator regulatory frameworks

Some system security services (e.g. frequency or voltage control) are provided through 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 to 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 be likely to be outweighed by the costs and complexity associated with participation in any centrally dispatched mechanism. Through aggregation, distributed energy resources are provided an opportunity for participation in system security frameworks with an aggregator providing the interface between the distributed energy resources and AEMO, and being responsible for coordinating the provision of system security services (among any others).

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

222 AEMO and Energy Networks Australia, Open Energy Networks, consultation paper, June 2018.

Service Provider (the two frameworks for aggregation discussed in this section) from tendering or applying to AEMO to provide non-market ancillary services.[223] However, we note that this may not always be technically feasible. For example, a demand response aggregator would not be able to provide system restart services.

This chapter therefore considers aggregator regulatory frameworks for providing market ancillary services, i.e. FCAS.[224]

This section sets out:

- issues associated with the existing frameworks for aggregation of distributed energy resources
- a summary of the analysis and proposed solution in the draft report including stakeholder views on the draft report
- further analysis and the Commission's final recommendation.

D.3.1 Issues

The NER currently provides for two frameworks for distributed energy resource aggregation: the Small Generation Aggregator framework and the Market Ancillary Service Provider framework. While both of these frameworks allow for aggregation of resources in the NEM, the Small Generator Aggregator framework does not permit the aggregation of small generating units for the purposes of providing FCAS. The NER does also not make it clear that a Market Ancillary Service Provider could enable small generating units as part of its market ancillary service in relation to an ancillary service load. [225]

D.3.2 Draft report

In the draft report, we suggested 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.[226] This would provide flexibility for a range of business models that may emerge in this space:

- It would allow parties to aggregate small generating units to sell energy into the wholesale market and offer to provide FCAS, and be the financially responsible market participant (FRMP) for those units – Small Generation Aggregators.

223 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. For more information, see section 7.3 of the issues paper for this review.

224 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.

225 This issue is considered in more detail in the draft report. See: AEMC, Frequency control frameworks review, draft report, pp. 109-111, March 2018.

226 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.

- It would allow parties to aggregate small generating units and offer to provide FCAS only (i.e. not sell energy into the wholesale market), without also being the FRMP for those units – a Market Ancillary Service Provider.

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 the services they want to provide.

In addition, we noted that the successful participation of Market Ancillary Service Providers in ancillary service markets to date suggests that aggregated resources can be accommodated within this framework.

As such, we made a draft recommendation as follows:

DRAFT RECOMMENDATION 4: Aggregator regulatory frameworks

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.

Stakeholder views

Stakeholders generally supported these recommendations.[227]

ERM Power noted that the units providing market ancillary services should still be required to meet the requirements set out in the MASS.[228]

Energy Queensland considered that the performance standards required from aggregated distributed energy resources should be consistent with the requirements imposed on larger market participants providing market ancillary services.[229]

AEMO supported the changes to registration categories but considered there needed to broader consideration of issues relating to:[230]

- how storage technologies register in the NEM
- whether the Small Generation Aggregator and Market Ancillary Service Provider categories accommodate all potential technologies
- the specific requirements that may need to be imposed on new business models such as virtual power plants.

227 Submissions to draft report: Tiko Energy Solutions, p. 8; ERM Power, p. 4; Tesla, p. 4; Clean Energy Council, p. 4; Meridian Energy, p. 2; AEMO, p. 10; ARENA, p. 5; AGL, p. 4; ENGIE, p. 5, S & C Electric, p. 8.

228 ERM Power, submission to draft report, p. 4.

229 Energy Queensland, submission to draft report, p. 5.

230 AEMO, submission to draft report, p. 10.

A number of stakeholders highlighted broader concerns relating to the regulatory treatment of storage and virtual power plants, and the visibility of distributed energy resources. These concerns are considered in section D.3.3.

Technical working group

The Commission help a technical working group meeting on 22 May 2018.

Working group members reiterated their support for the recommendation made in the draft report. Some raised concerns about the impact of large scale aggregation of distributed energy resources on the network and on power system security more broadly.

AEMO noted that they are undertaking trials of aggregated distributed energy resources to test the ability to suitably provide different FCAS. It is also looking at options for metering and verifying the response from an aggregated portfolio that relies on measuring the response at a subset of units to reduce the costs of complying with the MASS.

D.3.3 Analysis and recommendations

Allowing new participants to provide market ancillary services through aggregated distributed energy resources would have the benefits of:

- allowing for the least cost provision of services necessary to maintain power system security by utilising more available resources
- increasing competition in FCAS markets, potentially leading to lower FCAS costs
- diversifying the providers of these services
- providing greater opportunities for efficient investment and utilisation of FCAS capability from distributed energy resources.

We acknowledge that there are likely to be technical challenges arising from the participation of aggregated small generating units in providing FCAS.[231] In addition, there are regulatory challenges associated with emerging business models, such as virtual power plants, that the AEMC and AEMO are working together to address.[232] However, before these broader issues are addressed, the AEMC considers there is value in changing existing frameworks for aggregation. Doing so will provide greater opportunities to understand the associated challenges while facilitating increased competition and innovation in the provision of FCAS.

The Small Generation Aggregator framework has typically been used to aggregate 'larger' small generating units, for example on behalf of commercial or industrial customers. Currently, there are 15 market Small Generation Aggregators in the NEM. Example of the generating units these participants have aggregated include:

- diesel generators
- co-generation and tri-generation plants
- small pumped hydro

231 These technical challenges are discussed in more detail in [section XX] of this paper.

232 Some of the challenges relating to virtual power plants are considered in the next steps section of this appendix.

- industrial solar PV.

These Small Generation Aggregators are required to be the financially responsible market participant at the connection point for these units. They are also required to satisfy the relevant prudential requirements in Chapter 3 of the NER.[233]

The resources aggregated by Small Generation Aggregators are potentially well suited to providing a response to a frequency disturbance. As such, the Commission is of the view that allowing small generation aggregators to provide FCAS would improve competition in FCAS markets and allow for more efficient operational decisions for these Small Generation Aggregators.

It not clear whether the small generation aggregation framework lends itself to accommodating emerging business models focused on 'smaller' small generating units (such as households), where the consumer retains a separate relationship with a retailer (i.e. the financially responsible market participant). Consequently, the Small Generation Aggregator framework itself may not allow the participation of virtual power plants who may intend to participate in FCAS markets.

AEMO, the AEMC and the AER are working together to establish a NEM virtual power plant trial program. The trials will be used to support an understanding of the technical and regulatory requirements associated with virtual power plants providing energy, FCAS and network support services. The intention is that the trials will inform any future amendments to the regulatory framework to enable the power system and consumer benefits virtual power plants can offer.

While the AEMC is of the view that there is value in changing the existing frameworks for aggregation in the short term, these rule changes may be more appropriately considered when the outcomes of the NEM virtual power plant trial program are more advanced. This would be able to inform whether changes to the Small Generation Aggregator framework would encompass virtual power plants and other emerging business models.

In the draft report, the Commission considered that a Market Ancillary Service Provider would not able to aggregate small generating units for the purpose of classifying them as ancillary service generating units and providing market ancillary services. However, this may not be the case. The NER does not explicitly allow for a Market Ancillary Service Provider to aggregating small generating units to provide FCAS. However, because these generation sits behind a connection point with a retailer as the financially responsible market participant, the ancillary services provided by the Market Ancillary Service Provider by way of small generating units will always be at a load connection point (and seen in central dispatch as a reduction in load – or negative load).

233 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.

As a result, changes to the NER would not be required for a Market Ancillary Service Provider to provide FCAS from small generating units. However, this is not clear from the current wording of the NER nor the MASS.

The Commission therefore recommends that a rule change request be submitted to:

- allow Small Generation Aggregators to classify small generating units as ancillary service generating units for the purposes of offering market ancillary services.
- clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units.

However, as the AEMC will be working collaboratively with AEMO and the AER to develop trials of virtual power plants in the NEM to understand the regulatory issues arising, this rule change may be more appropriately considered when the outcomes of these trials are more advanced. In addition, the Commission will work with AEMO to undertake a broader review of the registration categories in the NER to determine whether they sufficiently accommodate and support the participation of new technologies (see section D.7).

Assessing the rule change proposal when the 6trials are more advanced would allow the Commission to better consider the interaction between changes to these aggregation frameworks in the context of a broader review of registration categories and being informed by the outcomes of virtual power plant trials.

The final recommendation relating to aggregator regulatory frameworks is as follows:

RECOMMENDATION 4: AGGREGATOR REGULATORY FRAMEWORKS

That AEMO submit a rule change request to:

1. clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units
2. enable 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.

Proposed rule drafting that could accompany this rule change request is set out in Appendix F.

D.4 FCAS bid size

This section sets out:

- issues associated with current minimum increment for FCAS bids
- a summary of the analysis and proposed solution in the draft report
- a summary of stakeholder views of the draft report
- the Commission’s further analysis.

D.4.1 Issue

A 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.[234]

The NER also requires a minimum offer of a whole MW, which would exclude the participation of aggregators with portfolios with less than 1 MW of available capacity. Some stakeholders have indicated that 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.

Restricting bids to 1 MW increments requires an aggregator to build up a portfolio of at least 1 MW, 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 2.5 MW of FCAS. Under the current arrangements, until that aggregator is able to acquire another 0.5 MW of capacity, the full capability of the resources under control of the aggregator may be underutilised.

D.4.2 Draft report

In the draft report, the Commission did not make a draft recommendation relating to the size of FCAS bids. We sought stakeholder views on:

- whether this restriction in the NER posed a barrier for aggregated distributed energy resources
- what the costs and benefits of removing this requirement would be.

Stakeholder submissions

Stakeholder provided mixed views on the benefits of removing the whole MW increment requirement for bids from the NER.

Both Engineers Australia and ARENA noted that removing the requirement would likely facilitate greater contributions from aggregators of distributed energy resources.[235] S&C Electric Company noted that services provided in quantities of less than 1 MW may have a measureable impact on the NEM and provide a valuable service.[236]

Origin Energy, ARENA and AEMO suggested that any change to the requirement should consider the extent of the benefits as well as the costs imposed.[237] AEMO noted that the costs would include having to make changes to systems, registration, dispatch processes and verification. AEMO suggested that there should be a thorough analysis of costs, which has not been undertaken to date.[238]

234 Clause 3.8.7A(i) of the NER requires market ancillary service offers to be made in whole MWs.

235 Submissions to draft report: Engineers Australia, p. 10; ARENA, p. 5.

236 S&C Electric Company, submission to draft report, p. 8.

237 Submissions to draft report: Origin Energy, p. 3; AEMO, p. 9; ARENA, p. 5.

238 AEMO, submission to draft report, p. 9.

D.4.3 Analysis and recommendation

While the Commission considers that removing the whole MW increment from the NER would allow for greater distributed energy resources participation, it is not clear that the benefits of doing so would outweigh the costs. We therefore suggest that AEMO undertake an assessment of the costs and benefits of changing this requirement at a time where there is a greater level of distributed energy resources participation. If AEMO finds that there would be a benefit to removing this requirement, it could submit this to the Commission to be considered through a rule change request.

D.5 Connection arrangements and AS 4777

Distributed energy resources connected to the network 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.[239] 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 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".[240] The exception is that micro-embedded generation is defined in the NER by reference to Australian Standard (AS) 4777.

The lack of prescription in the NER provides the potential for simpler and less complex connections to the network for distributed energy resources. However, this may also mean that connection frameworks are inconsistent across DNSPs, lacking in transparency and lacking justification for costs and technical requirements imposed in the connection process.

This section outlines:

- issues with the connection arrangements and AS 4777 that may be inhibiting the participation of distributed energy resources in system security frameworks

239 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.

240 See clause 5A.B.2(b)(4) of the NER.

- a summary of the analysis and proposed solution in the draft report including stakeholder views on the draft report
- further analysis and the Commission's final recommendation.

D.5.1 The issue

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.

Australian Standard 4777

Australian Standard 4777 applies to low voltage inverters connected to the power system.[241] 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 legislation. The term micro-embedded generator is defined in the NER with reference to AS 4777 and several DNSPs, including Ausgrid, Energex and Ergon Energy, refer to the standard 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, 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 voltage.

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

241 The standard applies to inverters up to 200kVA connected to low voltage parts of the grid.

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. This was noted in AEMO's 2017 review of the MASS, where AEMO suggested that it would not be appropriate to aggregate and offer to the market any services mandated through AS 4777.[242]

To date, distributed energy resources have had a limited role in providing system security services. If this were to change, the obligations imposed through connection arrangements and AS 4777 may hinder increased participation.

D.5.2 Draft report

The draft report highlighted issues arising from the connection frameworks for distributed energy resources, namely:

- 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 draft report therefore concluded 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.

The draft report set out the Commission's view that the efficient uptake of distributed energy resources is supported when 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 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.

The Commission did not consider there to be value in harmonising the Chapter 5 and Chapter 5A connection arrangements, or to apply prescriptive technical requirements for the connection of distributed energy resources in Chapter 5A of the NER. Doing so may impose material new costs and delays to connection, and may fail to accommodate the different technical characteristics of each distribution network in the NEM. Rather, the Commission was of the view that these requirements should be set by DNSPs in a manner that provides transparency and justification for these requirements.

242 AEMO, Market ancillary services specification, Issue paper, January 2017, p. 18.

Energy Networks Australia is currently undertaking a process to establish nationally consistent technical guidelines for DNSP connection arrangements.[243] The review is being undertaken following recommendations made in the Energy Networks Australia/CSIRO *Electricity network transformation roadmap*, and the Finkel Panel Review. The *National DER Connection Guidelines* will set out the framework, principles, approach and technical settings for NSPs to adopt in the development and application of their technical requirements for grid connection of distributed energy resources. The ultimate aim of the guidelines is to facilitate the efficient integration of distributed energy resources into the grid. In preparing the guidelines, the Energy Networks Australia will consult with the Commission, AEMO, the AER, the Clean Energy Council and Energy Consumers Australia.

Our draft recommendation was therefore to use this process 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.

DRAFT RECOMMENDATION 6: Connection arrangements and AS 4777

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 encouraged stakeholders to provide input into the development of these guidelines.

Stakeholder views

Connection frameworks

In its submission to the draft report, AEMO agreed that the connection framework should be timely, adaptive to local DNSP requirements, and provide consumers with the opportunity to optimise the value of their distributed energy resources. AEMO, submission to draft report, p. 12. [244]

Tiko Energy Solutions recommended the connections framework under Chapter 5A of the NER be extended to cover the connection of other residential loads such as air conditioners, heat pumps, electrical heating and electric hot water systems.[245] It also submitted that the framework should refrain from imposing further complication on the connection process, and limit reliance of standards such as AS 4777.[246]

243 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

244 AEMO, submission to draft report, p. 12.

245 Tiko Energy Solutions, submission to draft report, p. 8.

Tiko Energy Solutions warned against DNSPs imposing requirements during the connection process that limit the ability for distributed energy resources to compete to provide services to the rest of the power system.[247] AGL supported further consideration of the connection frameworks and any restrictions they might impose on distributed energy resources, particularly in relation to hybrid systems.[248]

AGL encouraged the Commission to review the connections framework in Chapter 5A and consider whether:

- there is sufficient transparency
- justification should be provided by NSPs for any technical requirements
- connections are processed in a timely manner.

Tesla suggested that the AER provide transparency on the average connection times for individual DNSPs to encourage streamlining of approaches.[249]

Energy Networks Australia's process to establish nationally consistent guidelines

Energy Networks Australia welcomed the Commission's support of its nationally consistent connection guidelines and supported the call for broader stakeholder input.[250] ENGIE, TransGrid, the Clean Energy Council, Tesla and Meridian Energy supported Energy Networks Australia's development of a nationally consistent framework.[251] Energy Queensland noted that its member DNSPs were actively inputting into the guidelines.[252] AEMO supported the Energy Networks Australia process but noted some limitations:[253][254]

- Complete consistency across the jurisdictions will not be efficient or feasible, with DNSPs requiring some flexibility depending on the specific needs of the local network.
- It is not proposed that the national connection guidelines would be mandatory, so their consistent application will depend on individual DNSPs' willingness to adhere to them, in the absence of any regulatory obligation.

Requirements imposed through connections

AEMO submitted that connection frameworks need to be able to take into account the system security impacts of distributed energy resources.

Tesla supported an approach to distributed energy resource connections that does not impose static limits on capacity connected and is able to allow for varying levels of export.[255] The Clean Energy Council also raised concerns regarding hard exports limits, submitting that this would constrain the ability for distributed energy resources to provide

246 Ibid, p. 9.
247 Ibid.
248 AGL, submission to draft report, p. 2.
249 Tesla, submission to draft report, p. 6.
250 Energy Networks Australia, submission to draft report, p. 3.
251 Submissions to draft report: ENGIE, p. 5; TransGrid, p. 3; Tesla, p. 5; Meridian Energy, p. 3.
252 Energy Queensland, submission to draft report, p. 7.
253 AEMO, submission to draft report, pp. 12-13.
254 Ibid, pp. 11-12.
255 Tesla, submission to draft report, p. 5.

system security services.[256] AGL considered that network connection agreements and regulatory frameworks should not compromise the investment that the customer has made, limit energy market interaction or compromise the ability for service provision.[257]

Tesla recommended that, when trialling the capability of distributed energy resources to provide market ancillary services, consideration be given to the capability that could be reasonably required by the NSP to meet it service obligations, particularly in relation to voltage control and active power support.[258]

The Clean Energy Council also raised concerns about the risk of DNSPs mandating service provision from distributed energy resources as a condition of connection. It suggested that there should be clear guidance provided in the Energy Networks Australia connection guidelines on which party should determine the services that should be provided as a condition of connection.[259]

PIAC supported consideration of inverter standards for distributed energy resources if this would remove barriers to the most effective forms of supply for managing power system frequency.[260]

Technical standards for distributed energy resources

AEMO supported the development of a set of technical standards for distributed energy resources. It considered the benefits of doing so would be:[261]

- enabling the participation of distributed energy resources in the future which is cheaper to enable in the connection process than retrofitting
- increasing the local hosting capacity of the network by better understanding the technical capability of distributed energy resources to be co-located in a region of a distribution network
- allowing third parties to dynamically control the export of distributed energy resources to allow for the secure operation of the power system.

AEMO explained that it has commenced an investigation into the technical standards it thinks needs to be applied to distributed energy resources from a security and reliability perspective.[262]

Australian Standard 4777

AGL noted that the revised AS 4777 includes more stringent disconnection requirements. Combined with the high grid voltage seen in certain jurisdictions, this is resulting in a high rate of inverter disconnection. This is preventing storage inverters from participating in frequency response programs, such as the “virtual power plant”. AGL also noted that there

256 Clean Energy Council, submission to draft report, p. 6.
257 AGL, submission to draft report, pp. 5-6.
258 Tesla, submission to draft report, pp. 5-6.
259 Clean Energy Council, submission to draft report, p. 5.
260 PIAC, submission to draft report, p. 4.
261 AEMO, submission to draft report, p. 12.
262 Ibid.

should be further consideration of harmonising the requirements in AS 4777 with other international standards.[263]

AEMO noted that the process for revising AS 4777 was lengthy and may not be able to maintain pace with the evolution of the power system.[264]

D.5.3 Analysis and recommendation

The Commission's final position reflects its position in the draft report.

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). Connection arrangements should also not provide DNSPs with a monopoly access to services that can be provided by distributed energy resources.

We support the Energy Networks Australia process to harmonise connection frameworks across DNSPs. The process has generally been supported by stakeholders and has received significant stakeholder engagement. The AEMC is on the steering committee. We have provided, and will continue to provide, input into the development of the guidelines.

The process has the potential to ameliorate a number of stakeholder concerns relating to the connection framework for distributed energy resources. However, the project team acknowledges the concerns raised by AEMO and AGL,[265] namely that the proposed guidelines:

- are not binding on DNSPs in a regulatory sense
- will not be nationally consistent unless all DNSPs commit to their implementation, and therefore may result in a continuation of DNSPs' current approach without providing any more value to consumers or simplifying the connections process
- may result in "lowest common denominator" requirements, i.e. the most onerous requirements would be applied across the board to provide comfort to DNSPs and achieve national consistency.

Energy Networks Australia has produced a *Frameworks and principles guideline* for the actual technical guidelines. The objectives of the guidelines are to:

- establish clear technical requirements for grid connection to each distribution network
- provide for a level of consistency between Australian DNSPs' technical requirements, both in terms of structure of presentation and the requirements themselves
- ensure that DNSPs' technical requirements are consistent with the NEO – that is, that the technical requirements give regard to the long-term interest of consumers by

263 AGL, submission to the draft report, p. 2.

264 AEMO, submission to draft report, p. 12.

265 Submissions to the draft report: AGL, p. 2; AEMO, pp. 12-13.

appropriately balancing the economic benefits, costs and risks that the requirements impose upon the network, proponents and Australia's electricity system more generally.

Energy Networks Australia has acknowledged that while the framework is voluntary, all Australian NSPs have communicated the intention to adopt the requirements in the guidelines. Where DNSPs choose to adopt an alternative setting, structure or approach, they will need to justify within their own technical guidelines how the alternative settings increase the net economic benefits to Australia's electricity system (in terms of both network and proponent benefits, risks and costs).

The Commission considers that, in the first instance, it is prudent to use Energy Networks Australia's process to address stakeholder concerns with connections under Chapter 5A. The Commission agrees with the principles outlined by the Energy Networks Australia in the *Frameworks and principles guideline*. Some points to note include:

- We support making arrangements transparent, which includes providing justification for any costs imposed and any requirements mandated in the connection process.
- Where possible, connection frameworks should be consistent across DNSPs. Differences in network conditions will likely necessitate different requirements from individual DNSPs.
- If the connection of a distributed energy resource imposes a cost on the network, it is appropriate to recover costs in that connection process (if the customer agrees). The costs recovered should be proportional to the impact of the connection.
- Careful consideration should be given to how you assess whether technical requirements advance the NEO. For example, while it may be necessary to require distributed energy resources to reduce output to lower network voltages, imposing this requirement may prevent the same resource maintaining network voltages as a competitive service under a future framework.

To the extent that the Energy Networks Australia connection guidelines do not resolve stakeholder concerns regarding its application, it may warrant consideration of further prescription in the NER regarding the connection of distributed energy resources. In submissions, stakeholders suggested the NER could be amended to:

- contain a set of technical standards for distributed energy resource connections
- provide greater transparency in the connection process
- contain principles to guide the imposition of any mandated services
- set out statutory timeframes in the connection process.[266]

We consider that the Energy Networks Australia guidelines seek to address these concerns and subsequent to its implementation these issues should be reconsidered.

The national connection guidelines should also provide guidance on the circumstances in which it is necessary to impose a limit on connection sizes. Where a limit on the connection of an intermittent resource such as solar PV may be appropriate, this may not be the case when coupled with energy storage. Instead, it may be more prudent for there to be a limit

266 The AER could also report on the timeliness of the connection process in different distribution networks.

applied to the maximum power that can be injected into the grid at any given time. In its submission to the draft report, the Clean Energy Council noted the approach proposed by South Australia Power Networks, where, instead of imposing a 10kW limitation for single phase connections, it would allow up to 10kW of solar PV and up to 10kW of energy storage being co-located with a 5kW grid export limit.[267]

A static export limit is also likely to be a blunt approach to addressing the impact of distributed energy resources on the network. A more sophisticated approach would be to consider the introduction of dynamic constraints that limit the amount of energy being exported as necessitated by changes in network conditions.[268] This would allow consumers to install greater amounts of distributed energy resources and operate them in a manner that maximises consumer benefits without detrimentally impacting on the network.

The final recommendation is largely consistent with the draft recommendation.

RECOMMENDATION 5: CONNECTION ARRANGEMENTS AND AS 4777

That Energy Networks Australia, in developing its national connection guidelines, explicitly consider:

- 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 circumstances in which it is appropriate to limit the size of the connection, why it might be appropriate to limit the size of the connection and how this applies to hybrid systems
- the extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services or participate in other energy markets.

The Commission encourages stakeholders to input into the development of these guidelines.

Broader policy issues around distribution network access and connection for distributed energy resources are being considered in the Commission's 2018 *Electricity network economic regulatory framework* review.[269]

D.6 Technical interactions between distributed energy resources and the rest of the power system

Distributed energy resources providing system security services would have a multifaceted relationship with local network conditions. The local network must both be able to support

267 Clean Energy Council, submission to draft report, p. 7.

268 This approach was noted by Tesla in its submission to the draft report. See: Tesla, submission to the draft report, p. 5.

269 See: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1

and withstand the local provision of system security services. That is, the local network conditions must be such that system security services can physically be accommodated. 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 issues associated with distributed energy resources providing system security services

- the Commission's position on these issues in the draft report and stakeholder views to the draft report
- further analysis and the Commission's final recommendation.

D.6.1 The issue

This review is not specifically considering system security issues associated with the increasing uptake of distributed energy resources. As set out in section D.2.4, we consider that it is more appropriate for AEMO to identify these issues, and it has a range of work underway to do so. However, in having distributed energy resources providing system security services, there is the need to consider any new issues introduced alongside this service provision.

Two main concerns have been raised:

- Local network conditions may 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.

A better understanding of both concerns and how they can be managed is likely to be a necessary precursor to the widespread participation of distributed energy resources in system security frameworks.

D.6.2 Draft report

In the draft report, the Commission highlighted the two-sided interaction of network conditions and services from distributed energy resources reflecting the state of the network before and after the service provision:

- The distribution network needs sufficient thermal and network capacity prior to the provision of services to accommodate additional active or reactive power.
- The provision of services within the distribution network should not prevent the DNSP from being able to meet its service obligations.

Impact on ability to provide services

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.[270] To the extent that the grid might not have spare capacity, this can be managed through network constraints.

The ability for distributed energy resources to provide system security services is dependent on local network conditions. At a distribution network level, network conditions tend to be more variable and less closely monitored than at the transmission network level. 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 and dynamic control 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. While DNSPs monitor the available capacity in their networks, they do not have dynamic network constraints that constrain the dispatch of resources to manage power flows and maintain the network within its technical limits.

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) to input or withdraw power. 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 and 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, the ability for an aggregator to manage this risk is limited by the level of information it receives regarding the condition of the network. This may 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 services provided within distribution network

The provision of system security services themselves should not cause the power system to become less secure or prevent the DNSP from meeting its service obligations.

270 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.

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 within an appropriate range. 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 earlier. 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 intends to provide clarity on:

- how distributed energy resources can operate in a manner that allows the NSP to maintain network voltages and thermal limits
- 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 constraints, planned investments and the potential value of distributed energy resources in networks across the NEM.[271] 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.

Draft report conclusions

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:

271 See: https://arena.gov.au/project/aremi-project/

- 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.

Currently there has been limited experience with accommodating aggregated distributed energy resources. While it is generally acknowledged that there will be challenges associated with doing so, these challenges and how they are best addressed are relatively novel. It is not immediately clear that there needs to be regulatory changes that the Commission could make to improve the harmony between increasing orchestration of distributed energy resources and the rest of the power system. As such, we recommended that AEMO, NSPs and aggregators of distributed energy resources coordinate trials to better understand the challenges faced and how these challenges might interact with the current regulatory frameworks. The intention would be for these trials to inform any changes that may need to be made to regulatory frameworks.

DRAFT RECOMMENDATION 7: Technical interactions between distributed energy resources and the network

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.

Stakeholder views

Trials

Stakeholders generally supported the recommendation to undertake trials to increase understanding of the technical interactions between distributed energy resources and the broader power system.[272]

The Clean Energy Council urged AEMO to commence trials of distributed energy resources providing FCAS as soon as practicable.[273]

272 Submissions to draft report: Meridian Energy, p. 3; ENGIE, p. 5; Tesla, p. 6; Clean Energy Council, p. 5, TransGrid, p. 2.

273 Clean Energy Council, submission to draft report, p. 4.

Tesla noted that it is crucial that DNSPs be involved in these trials.[274] The Clean Energy Council suggested the scope of the trials should involve market participants, DNSPs and TNSPs so that the entire supply chain can be better informed about the potential benefits, challenges and opportunities involved with distributed energy resources.[275] TransGrid agreed that it was important for TNSPs to be involved in the trials to understand the impact on the transmission network.[276]

Tiko Energy Solutions raised the concern that impacts on the network could provide DNSPs with the ability to prioritise services from distributed energy resources to assist the network over other services such as FCAS.[277]

AEMO indicated that it is looking to also be involved in trials that demonstrate the capability of distributed energy resources to provide fast FCAS, as well as other system services, and will be developing frameworks that outline what these trials should address. AEMO is looking to demonstrate:[278]

- the ability of distributed energy resources to reliably provide all eight FCAS services (particularly the 'fast' services)
- capacity to provide services faster than the current requirements (which may inform changes to how FCAS are specified if found to be more efficient/effective)
- how to efficiently measure and verify FCAS provision from aggregated distributed energy resources (including sampling across a set number of units with high-speed monitoring).

Energy Networks Australia noted that several of its members had already conducted trials to assist with understanding the challenges associated with orchestrated distributed energy resources. It recommended that these trials could form the basis of future analysis and assist in the design of larger scale trials.[279]

AGL recommended that trials of aggregated distributed energy resources providing FCAS should seek innovative solutions through competitive tender processes with the broader industry instead of involving central procurement with NSPs or AEMO which could distort competitive FCAS market outcomes.[280]

TransGrid supported further technical analysis of aggregated distributed energy resources but cautioned against extrapolating the results of small trials to widespread participation.[281]

274 Tesla, submission to draft report, p. 6.
275 Clean Energy Council, submission to draft report, p. 5.
276 TransGrid, submission to draft report, p. 2.
277 Tiko Energy Solutions, submission to draft report, p. 9.
278 AEMO, submission to draft report, p. 11.
279 Energy Networks Australia, submission to draft report, p. 2.
280 AGL, submission to draft report, p. 6.
281 TransGrid, submission to draft report, p. 2.

Information sharing

Energy Networks Australia welcomed the opportunity to facilitate engagement between the Commission, AEMO and NSPs.[282]

Energy Networks Australia suggested that there is a need for greater transparency of the technical characteristics of aggregated distributed energy resources and suggested that there may be the need for technical standards to be applied to aggregators.[283]

AEMO suggested that, in addition to the challenges raised in the draft report, consideration should be given to the technical response of inverters that may restrict the ability of distributed energy resources under some or many network conditions.[284] In its submission, AEMO was supportive of a “heat map” approach to signaling opportunities for investment in distributed energy resources to provide local network services, and noted that greater communication between AEMO and DNSPs is required to mitigate potential impacts on the local network or the power system due to a coordinated operation of distributed energy resources.[285]

Energy Queensland highlighted the need to develop a mechanism to determine the quantity of exports that could be accommodated by the distribution network that reflects planned and unplanned outages.[286]

D.6.3 Analysis and recommendation

The technical challenges associated with the provision of FCAS within a distribution network are not well understood. Currently, there is limited visibility of the spare capacity in the distribution network and limited visibility of the quantity or intentions of the growing amount of distributed energy resources. Increasing this visibility will be crucial to unlocking the potential for distributed energy resources providing system security services (and other services) while also enabling NSPs to meet their service obligations. Increasing visibility in practice means facilitating the flow of pertinent information between interested parties, for example:

- DNSPs communicating to aggregators the voltages in the network that may impact the ability for distributed energy resources to provide FCAS, which an aggregator could reflect in its offer.
- Aggregators communicating the intention to provide FCAS to a DNSP that would allow the DNSP to operate the network in a manner that would accommodate that FCAS.

The Commission considers that undertaking trials would provide a valuable mechanism for better understanding the technical interaction between distribution level FCAS and the distribution network. AEMO, DNSPs and distributed energy resource aggregators should share information that would enable distributed energy resources to participate in the

282 Energy Networks Australia, submission to draft report, p. 2.
283 Ibid.
284 AEMO, submission to draft report, p. 13.
285 Ibid.
286 Energy Queensland, submission to draft report, p. 7.

provision of system security services without compromising the safe, secure and reliable operation of the power system. Trials would provide an opportunity to consider what information needs to be exchanged, the parties that need access to the information, and any possible changes to regulatory frameworks to better accommodate these services.

In its submission, Energy Networks Australia noted that a number of its members had already trialed aggregated distributed energy resources. In addition, AGL published a knowledge sharing report that highlights a number of the technical challenges it encountered with its VPP. In this report, AGL noted that 12.5% of the energy systems were experiencing persistently high voltages that triggered the anti-islanding settings in the inverters imposed under the recently revised AS4777. The experiences of Energy Networks Australia's members and AGL should provide insights for future trials.

Both AEMO and ARENA have committed to undertaking trials of aggregated distributed energy resources. On 15 June 2018, AEMO published a specification for distributed energy resources providing contingency FCAS. The specification sets out how the trial would consider different telemetry requirements such as using high speed metering on subset of units within a virtual power plant.[287]

The outcomes of these trials should also assist in the development of a future distribution market. This is considered more in section D.7.1.

RECOMMENDATION 6: TECHNICAL INTERACTIONS BETWEEN DISTRIBUTED ENERGY RESOURCES AND THE NETWORK

That:

1. when AEMO conducts trials of aggregated distributed energy resources providing FCAS, including virtual power plants, it assesses 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
2. when undertaking these trials, AEMO collaborate with interested and affected stakeholders including ARENA, the local DNSP, distributed energy resource aggregators, virtual power plants, neighbouring DNSPs and affected TNSPs.
3. 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

287 AEMO, Distributed energy resources FCAS specification, June 2018.

D.7 Next steps

In order to facilitate more opportunities for distributed energy resources to participate in system security frameworks, we have made a number of recommendations. These recommendations are to:

- expand aggregator frameworks in the NER to encompass small generating units for the purposes of FCAS market participation
- develop connection frameworks that do not inefficiently preclude the participation of distributed energy resources in system security frameworks
- undertake trials of distributed energy resources providing FCAS to better understand how this would operate in practice and the impact it has on the local network.

These recommendations provide opportunities for the Commission, AEMO and broader industry to understand how distributed energy resources might participate in future system security frameworks. They will also inform the evolution of the distribution network to one where consumers have more control over how their distributed energy resources are used while maintaining the safe, secure and reliable supply of electricity.

However, as has been noted by the Commission and by stakeholders, there are still a number of broader issues relating to the integration of distributed energy resources that require consideration, including:

- the development of a distribution market model
- the treatment of virtual power plants in regulatory frameworks
- the appropriateness of the existing registration categories in light of new technologies and business models
- allowing consumers to engage multiple service providers at a single connection point.

The AEMC is working with AEMO to develop a joint work program on distributed energy resources with the objective of better coordinating the various areas of work that the AEMC and AEMO are undertaking on a range of distributed energy resources-related issues, which includes consideration of the issues above.

An explanation of each issue is provided below, as well as a summary of stakeholder comments on these issues.

D.7.1 The development of a distribution markets

Technology and markets have significant progress to make to transition to a distribution network that facilitates the efficient operation of distributed energy resources. Implementing a framework for managing and optimising the dispatch of distributed energy resources will require further development and consultation as well as considerable time to implement. Further work on assessing the costs and benefits to consumers of DNSPs developing the capabilities to dynamically manage distributed energy resources will also need to be undertaken.

AEMO and Energy Networks Australia have published a paper seeking stakeholder views on the design of a framework for a more effective integration of distributed energy resources in the NEM.[288] The Commission encourages interested parties to make a submission to the joint AEMO/Energy Networks Australia process. The AEMC is working closely with AEMO and Energy Networks Australia through that consultation to understand the technical challenges and opportunities facing networks and potential frameworks to manage system operations and optimise distributed energy resources.

Through the 2018 *Electricity network economic regulatory framework review* the AEMC has explored aspects of the econmomic regulatory frameworks that are important to support the evolving role of DNSPs and the efficient integration of distributed energy resources now and into the future.[289] This includes consideration of:

1. financial incentives for NSPs, including an evaluation of whether the current mechanisms are likely to provide balanced incentives for network investment as technological change broadens the investment options that are available to them
2. changes required to the electricity distribution system to optimise the value provided by distributed energy resources and whether the current regulatory framework can support NSPs in efficiently integrating distributed energy resources
3. network expenditure and performance, and whether additional measures are needed to incentivise efficient future network expenditure.

D.7.2 The treatment of new forms of distributed energy resources orchestration in regulatory frameworks

In its submission to the draft report, AEMO considered that any changes to registration categories should consider whether the existing aggregator frameworks capture all potential technologies and virtual power plants.[290] AEMO noted that the unscheduled operation of virtual power plants could pose a risk to power system security.

AEMO suggested that factors to consider when looking at virtual power plants include:

- the communications and measurement infrastructure and capability necessary for a virtual power plant to participate in wholesale markets
- the location of units in the virtual power plant to be included in network constraints to inform when it may be necessary to constrain output or when value could be attributed to changing operation of the virtual power plant
- the available network capacity throughout the network that is able to accommodate changes in virtual power plant operations
- whether, if they were to participate in central dispatch, virtual power plants would be subject to the same requirements for compliance with dispatch instructions as existing scheduled resources.

288 See: https://www.energynetworks.com.au/open-energy-networks-consultation-paper

289 See: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1

290 AEMO, submission to draft report, p. 10.

TransGrid noted that NSPs need greater visibility of aggregated distributed energy resources. It proposed that they be considered as virtual generators and required to go through a connection and performance standard type process once they reach a certain size.[291]

As noted earlier in this paper, there are a growing number of business models looking to aggregate distributed energy resources and orchestrate their output. The scale of the coordinated output can rival the scale of transmission-connected generators. Some of the challenges this raises include:

- the extent to which large, unpredictable changes in distributed energy resources output impacts on forecasts of demand that guide generator dispatch
- the ability to maintain power system frequency within appropriate bounds following orchestrated swings in distributed energy resources output
- the impact on the network voltages and thermal limits.

The regulatory challenges of this include:

- **The appropriate technical requirements and how these requirements are imposed:** Generators connecting under Chapter 5 work through a set of performance standards so that AEMO and the NSP can understand the technical operation of the generator. The connection framework for distributed energy resources does not replicate the process for assessing a range of technical performance parameters for good reason. Doing so would impose costs on the connecting party, delay the connection process and likely provide limited benefit to the network. However, when 100 MW of distributed energy resources act in concert, it is likely to have a profound technical impact on the network. It is worth considering whether the obligations on generators with registered performance standards should be extended to virtual power plants.
- **How virtual power plants should participate in the wholesale market:** The capacity of virtual power plants has the potential to rival that of a scheduled generator. The prospect of virtual power plants responding to wholesale price signals raises questions of whether they should be involved in the central dispatch process. As such, consideration should be given to how virtual power plants could be incorporated into central dispatch to reduce the extent of any distortions they impose on the market.

The AEMC is working with AEMO to develop a joint work program on distributed energy resources with the objective of better coordinating the various areas of work that the AEMC and AEMO are undertaking on a range of distributed energy resources-related issues. One aspect of this work program is a collaboration between AEMO, the AEMC and the AER to establish a NEM virtual power plant trial program. The trials will be used to support an understanding of the technical and regulatory requirements associated with virtual power plants providing energy, FCAS and network support services. The intention is that the trials will inform any future amendments to the regulatory framework to enable the power system and consumer benefits virtual power plants can offer.

291 TransGrid, submission to draft report, p. 2.

D.7.3 A review of registration categories

There are two drivers for a possible review of registration categories as they are set out in Chapter 2 of the NER:

- The increasing uptake of storage has raised questions about whether the distinction between load and generation (and the current registration categories that apply – i.e. Customer and Generator) remains appropriate. This question is being explored by AEMO and to some extent through the Commission's *Coordination of generation and transmission investment review.*
- Recommendation 4 would, if a rule was made, result in registration categories that look more and more alike – that is, they would increasingly overlap in the services each category can provide. This may also be the case for any future registration category that accommodates virtual power plants (discussed above) or aggregation for the purposes of providing wholesale demand response (as is being explored through the Commission's *Reliability frameworks review*).

In its submission to the draft report, Tesla recommended that a rule change request be submitted that allows for aggregation of distributed energy resources to provide energy and FCAS under a single market classification.[292]

The Commission will work with AEMO to undertake a broader review of the registration categories in the NER to determine whether they sufficiently accommodate and support the participation of new technologies, (for example, virtual power plants), and that these potential overlaps in registration categories are appropriate.

D.7.4 Allowing consumers to access multiple service providers at a single connection point

Under the current regulatory arrangements, there is a single FRMP at each connection point. That FRMP is responsible for purchasing and selling all electricity flowing into and out of that connection point in the wholesale market.

This means that under current arrangements, distributed energy resources participating in the wholesale market must do so through the FRMP. For residential consumers, the FRMP is a retailer.

AEMO noted that consideration of the regulatory barriers to participating in FCAS should also address the need to create pathways for multiple parties to access a customer (i.e. allowing for aggregators other than the customer's retailer), without having to create and pay fees for a duplicate NMI and connection point.[293]

Greater participation of distributed energy resources in the wholesale market could be enabled by:

- Allowing consumers to engage multiple FRMPs at a connection point. This could allow one FRMP to aggregate just the distributed energy resources (e.g. solar and a battery) connected at a residential premises, and another to manage the customer's residual

292 Tesla, submission to draft report, p. 4.
293 AEMO, submission to draft report, p. 10.

load. However, where these distributed energy resources are used to offset retail costs, having them separately retailed by a second FRMP may not provide value to the consumer.

- Alternatively, an import FRMP/export FRMP relationship could be set up. This would allocate the electricity imports to one FRMP (which could be a traditional retailer) and electricity exports to a second FRMP (which could be a Small Generation Aggregator). This would allow the consumer to maximise the level of consumption it offsets using its distributed energy resources and still have the opportunity to export energy into the wholesale market.

The final report for the Commission's *Reliability frameworks review* recommended a rule change be submitted to allow consumers to access multiple services providers at the same connection point.[294]

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

E AEMO'S MARKET ANCILLARY SERVICES SPECIFICATION

In the draft report published for this review in March 2018, the Commission set out the following conclusions:

- Aspects of the MASS potentially constitute a barrier to the distributed energy resources looking to provide market ancillary services.
- the MASS is an area of focus in respect of the current frequency control regulatory frameworks that could be changed without changes to the NER.

This appendix sets out:

- the recommendations made by the Commission in the draft report in respect of the above points
- a summary of stakeholder views on those recommendations, based on submissions to the draft report
- the Commission's subsequent analysis, conclusions and final recommendations.

E.1 Overview

This appendix outlines the proposed approach to the final report for the work stream of the *Frequency control frameworks review* (the 'review') considering possible changes that could be made to the market ancillary services specification (MASS) published by the Australian Energy Market Operator (AEMO).

In order to provide market ancillary services under the current arrangements, market participants are required to comply with the MASS published by AEMO. Currently, the only market ancillary services in the NEM are FCAS.[295]

AEMO is required under the NER to publish the MASS which details each market ancillary service and the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant market ancillary service.[296]

Separate to the MASS, AEMO provides participants with a FCAS verification tool that contains the algorithms that are used by AEMO to verify the contingency services provided by a market ancillary service facility.

AEMO is able to make changes to the MASS and is required to comply with the Rules consultation procedure when undertaking changes.[297]

The MASS has received increased attention of late. This has been driven by:

295 There are also non-market ancillary services which are ancillary services not acquired by AEMO through the spot market. These services include network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS). The MASS does not apply to these services.

296 Clause 3.11.2 (b) of the NER.

297 Clause 3.11.2 (d) of the NER.

- higher FCAS prices encouraging greater numbers of participants to register to provide FCAS and therefore needing to comply with the requirements set out in the MASS
- challenges encountered in the MASS by participants seeking to provide FCAS who employ newer technologies that traditionally have not provided FCAS.

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.[298]

In the draft report, the Commission noted that there are changes that could be made to the MASS to facilitate or better value the provision of market ancillary services from new resources, including batteries, aggregated distributed energy resources and demand response. Possible changes to the MASS were presented in two work streams:

- **The participation of distributed energy resources in system security frameworks** – the MASS was flagged as potentially constituting a barrier to the distributed energy resources looking to provide market ancillary services.
- **Future FCAS frameworks** – the MASS was noted as an area of focus in respect of the current frequency control regulatory frameworks that could be changed without changes to the NER.

For the final report, the work relating to the MASS has been collated and is presented in this appendix.

The recommendations set out in this appendix have been formulated on the basis of stakeholder comments that were received in response to the draft report and the Commission's analysis.

The Commission notes that AEMO have stated their intention to undertake a review of the MASS, commencing shortly. AEMO noted that it has been working with stakeholders on issues raised with the MASS. This review is intending to consider the interaction between services specified in the MASS as well as incorporating any lessons learned following proposed trials of distributed energy resources providing FCAS.

In addition, we are working with AEMO to develop a joint work program on distributed energy resources, with the objective of better coordinating the various areas of work that both bodies are undertaking on related issues.

E.2 Draft report

This section summarises the aspects of the draft report that related to the MASS and the relevant comments made in stakeholder submissions.

E.2.1 Summary of draft report

In the draft report, we considered:

298 AEMO, Market ancillary service specification review - issues paper, January 2017.

- whether the MASS might pose a barrier to the provision of system security services from distributed energy resources.
- changes to the MASS that could be made to facilitate FCAS from new technologies without requiring changes to the NER.

The draft report highlighted some potential barriers to distributed energy resources providing FCAS under the current MASS, including:

- Requirements for high speed metering when providing fast FCAS that has an associated cost which may be prohibitive to individual distributed energy resources. Currently, the MASS requires providers of fast FCAS to meter and verify a response to a frequency disturbance with a 50ms resolution at each unit providing a response. This is achievable for a large, single unit. However, it is likely to impose significant costs when the response is being provided by a large number of small units.
- The communication timeframes for the provision of regulating FCAS in response to an automatic generator control (AGC) signal from AEMO which may need to go through a third party aggregator before being received by the distributed energy resources.
- The process for registering FCAS capacity may undervalue the contribution of newer technologies, such as aggregated batteries.

We also noted that the ability for the MASS to accommodate distributed energy resources was impacted by the need to better understand the technical capabilities of distributed energy resources providing FCAS. As such, we recommended that trials be undertaken that would help increase the understanding of these technical challenges. These trials would be able to inform a review of the MASS to remove any barriers to FCAS being provided efficiently by distributed energy resources.[299]

While trials provide a useful opportunity to demonstrate the viability of new technologies in providing market ancillary services, we noted that there has so far been limited detail publicly provided by AEMO regarding the technologies or service characteristics that could or would be trialed.

The draft report also highlighted the MASS as a potential avenue for making changes to frequency control frameworks without making changes to the NER. The NER constrains the number of FCAS markets that exists by specifying that there must be eight services - regulating raise and lower services, and six contingency services.[300] However, the specification of the technical characteristics of the services resides within the MASS and is within the scope of AEMO to change as needed. An important question that we raised in the draft report is whether these markets remain relevant in terms of meeting the emerging needs of frequency control in the NEM.

As it is the MASS that specifies the technical characteristics of the services, it is also open for the MASS to be changed to redefine the services.

299 The option to undertake trials was an addition made following the most recent review of the MASS in 2017.

300 Clause 3.11.2 of the NER.

In the draft report, we recommended that consideration should be given to how the MASS could define FCAS to deliver the most valuable combination of services to manage frequency, including capturing the services that could be provided by faster, more responsive technologies. In support of this consideration, we recommended that AEMO undertake further investigations into the emerging capabilities of fast frequency response technologies including trials of various technology types to inform the development of future service specifications.[301]

E.2.2 Stakeholder views

Stakeholders were generally supportive of a review of the MASS to better incorporate newer technologies.[302]

AEMO noted that it has been working with stakeholders on issues raised with the MASS and will be undertaking a review.[303]

Aspects of the MASS that should be considered

Fluence suggested that AEMO consider the accuracy and speed of response achievable with newer technologies when reviewing the MASS.[304]

ERM Power noted that technical obligations should be consistent across current providers of market ancillary services and aggregated small generating units.[305] Energy Queensland also submitted that aggregators should be subject to the same performance standards applied to larger market participants.[306]

Tiko Energy Solutions noted that consideration should be given to the trade-off between the number of data points necessary for providing FCAS and the costs linked to the transmission and storage of the data for the market participants.[307] AEMO agreed that having FCAS being provided at multiple connection points would impose an economic and data impost on participants.[308]

Trials

Lyon Group supported undertaking trials of distributed energy resources providing FCAS.[309] Energy Queensland supported trials and greater consideration of how the communication between the market operator and aggregated portfolios would work in practice.[310]

301 AEMO is also undertaking trials of wind farms providing FCAS. These trials have demonstrated the capability of wind farms to participate in the existing slow and delayed FCAS markets but not the fast FCAS markets. The trials have demonstrated the ability of the wind farms to provide regulating FCAS.

302 Submissions to draft report: Energy Networks Australia, pp. 1-2; Tesla, p. 5; Meridian Energy, p. 3; TransGrid, p. 4; Lyon Group, p. 3.

303 AEMO, submission to draft report, p. 11.

304 Fluence, submission to draft report, p. 6.

305 ERM Power, submission to draft report, p. 4.

306 Energy Queensland, submission to draft report, p. 5.

307 Tiko Energy Solutions, submission to draft report, p. 8.

308 AEMO, submission to draft report, p. 11.

309 Lyon Group, submission to draft report, p. 3.

310 Energy Queensland, submission to draft report, p. 6.

Tesla supported using trials of aggregated distributed energy resources to inform a review of the requirements imposed through the MASS. Tesla supported a collaborative approach to these trials between aggregators, AEMO and relevant DNSPs.[311]

AEMO has committed to undertaking trials that would seek to demonstrate the capability of distributed energy resources to provide FCAS. AEMO will be developing frameworks which outline what these trials should address, and will use outcomes to inform a review of the MASS. These trials would seek to demonstrate:[312]

- the ability for distributed energy resources to participate in all eight FCAS markets
- the capability to provide services faster than existing FCAS (which could then in turn inform changes to how FCAS is specified)
- how to efficiently measure and verify FCAS provision from aggregated distributed energy resources (including sampling across a set number of units with high-speed monitoring).

E.3 The market ancillary services specification

E.3.1 Overview of the MASS

AEMO is required under the NER to publish the MASS containing at a minimum:[313]

- 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.

The MASS sets out the detailed specification of the market ancillary services and how a market participant's performance is measured and verified when providing these market ancillary services.

AEMO also publishes an FCAS verification tool that is primarily intended as a compliance tool to assess performance of enabled facilities during a contingency event but can also be used to help participants calculate the level of contingency 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 quantities of contingency services provided by a market ancillary service facility.[314]

In the connection process, a generator will agree on a droop setting with the relevant network service provider. This agreed droop setting sets the proportionality of the facilities response to a frequency deviation where proportional frequency control is used. As a result, the agreed droop setting will impact on the ability of a market participant to provide contingency FCAS. In the case of a switching control frequency response, droop is not used and a frequency setting/relay will be used to provide a stepped response to changes in frequency.

311 Tesla, submission to draft report, p. 5.

312 AEMO, submission to draft report, p. 11.

313 Clause 3.11.2(b) of the NER.

314 AEMO, Market ancillary service specification, July 2017, p. 12.

The MASS requires the equipment used to monitor and record the response of ancillary service facilities to:[315]

- 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[316]
  - intervals of four seconds for regulating, slow and delayed raise and lower services.

E.3.2 How do participants register FCAS capacity?

Contingency services

The current contingency services are fast, slow and delayed raise and lower services. The amount a participant can provide of each service is defined as the lesser of twice the time average of the response (in MWs) between:[317]

- zero and six seconds, and six and 60 seconds for fast services
- six and 60 seconds, and 60 seconds and five minutes for slow services
- 60 seconds and five minutes, and five minutes and ten minutes for delayed services.

The extent of the response is only considered once the frequency leaves the normal operating frequency band.[318]

The amount of response that a participant is assumed to provide is based on what the participant would be expected to deliver in accordance with a standard frequency ramp rate to the reference frequencies. The MASS and FCAS verification tool currently have input parameters for the standard frequency ramp rate and reference frequencies, including a frequency dead band for a contingency response:

- 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
- **Reference frequencies** of 49.5 – 50.5 Hz for the mainland and 48 – 52 Hz for Tasmania. This represents the frequency at which all enabled contingency FCAS should be activated. These frequencies correspond to the containment settings in the frequency operating standard for generation and load events for the mainland and for any credible contingency in Tasmania.

315 Ibid.

316 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 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.

317 AEMO, Market ancillary services specification, July 2017, p. 13, 17, 20.

318 This effectively means the normal operating frequency band is a dead band for a frequency response to a contingency event.

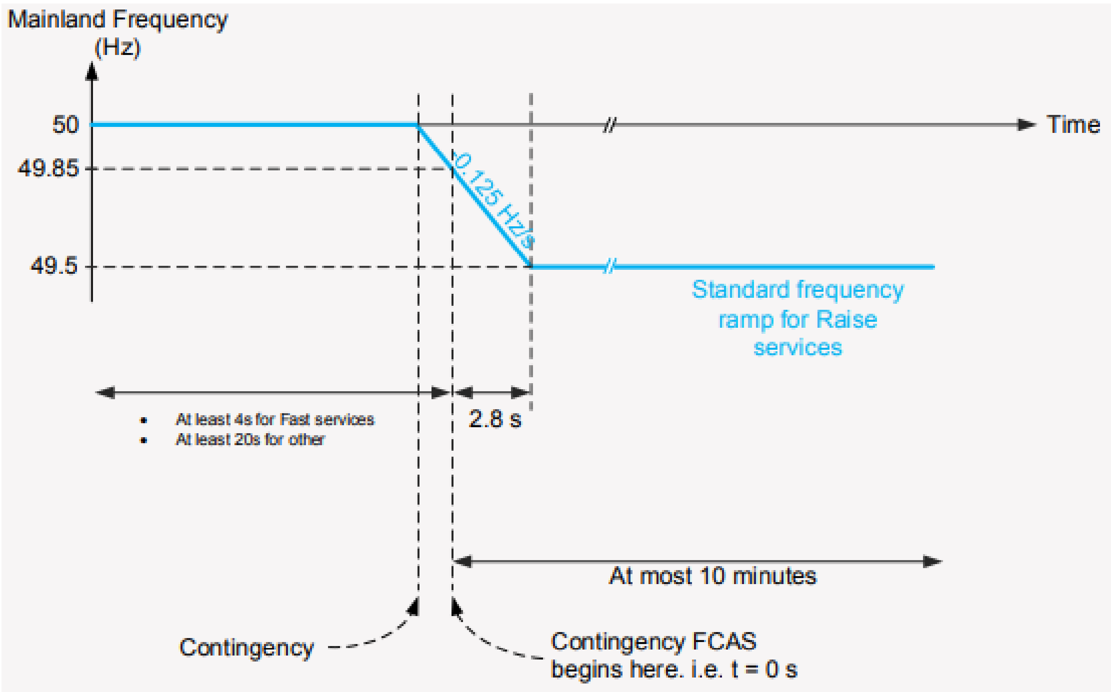
- A **standard frequency ramp rate** of 0.125 Hz per second, which is the assumed rate of change of frequency of the power system following a contingency event.

An example of the interaction between these settings (for a contingency event in which frequency falls outside the normal operating frequency band) is demonstrated in Figure E.1. This figure illustrates the interactions between the assumptions used in the MASS and FCAS verification tool:

1. A generation or load contingency occurs while the frequency is at 50 Hz. Following the contingency, the frequency is assumed to fall at 0.125 Hz per second.
2. The frequency leaves the frequency dead band at 49.85 Hz. At this point, contingency FCAS starts to respond.
3. Frequency continues to fall at 0.125 Hz per second, it reaches the reference frequency of 49.5 Hz 2.8 seconds after it leaves the frequency dead band.

When the power system frequency reached 49.5 Hz, a participant is expected to have provided its contingency response.

Figure E.1: **Standard frequency ramp for regions other than Tasmania**



Source: AEMO, *Market ancillary services specification*, 30 July 2017, p. 29.

On 15 June 2018, AEMO published a specification for distributed energy resources providing contingency FCAS. The specification sets out how the trial would consider different telemetry requirements such as using high speed metering on subsets of units within a virtual power plant.[319]

Verifying the amount of contingency FCAS provided

To verify the amount of FCAS a participant provided following a contingency event, the FCAS verification tool converts details about a plant into a capacity that can be registered for each contingency service. The approximate steps are as follows:

1. Input a trace of the output of a generator or load alongside the power system frequency to show how the plant responds to changes in frequency.[320]
2. Make a number of adjustments to the trace to understand the extent of the frequency response, including:
    a. Discount any response from the plant prior to frequency leaving the frequency dead band[321]
    b. Removing any inertial contribution[322]
3. Calculate the level of generation or load that would have been observed in absence of a frequency response
4. The amount of frequency response that is capable of being provided is then calculated as equal to the *difference* between the adjusted response and the level of generation/load that would have been observed in absence of a frequency response.
5. This amount is then split between difference services to account for double counting of services that overlap, i.e. fast and slow, and slow and delayed.

Regulating services

The current regulation services are the regulating raise and lower services. These services are designed to manage minor variations to system frequency within the normal operating frequency band following small deviations in the demand/generation balance within the five minute dispatch interval and are controlled through the AGC system.

The regulating FCAS capability of a facility is a function of its technical performance characteristics as set out in the generator technical performance standards which are registered with AEMO. The actual enablement level for a facility in any dispatch interval will vary with the competitiveness of the facilities bid and due to co-optimisation with the facilities bid in the energy market.

Verifying the amount of regulating FCAS provided

The process of verifying the amount of regulating FCAS is less clear than providing contingency FCAS.

319 AEMO, Distributed energy resources FCAS specification, June 2018.

320 Participants also need to input dispatch targets and other relevant information relating to the operation of the plant of the timeframe of the trace.

321 Any changes in plant output within 49.85-50.15Hz is not counted as a frequency response that can be considered as a contingency response. This is because contingency services are only triggered outside of that frequency range.

322 The MASS intentionally discounts any inertial energy provided by a plant.

For the purpose of verifying the amount of regulating raise service or regulating lower service that can be delivered, the MASS sets out a process for assessing the regulating FCAS performance.[323]

E.4 Analysis

AEMO has committed to reviewing the MASS in their submission to the draft report as well as indicating the possible need to review the MASS in their paper looking at the performance of the Hornsdale Power reserve.[324] As such, this section highlights some aspects of the MASS that the Commission considers would benefit from consideration by AEMO through the review process.

When reviewing the MASS, AEMO will be considering how the MASS can capture the value of services participants can provide to maintain power system frequency.

There would benefit in industry consultation on how the MASS can best specify services that provide for frequency control and the appropriate way to value these services. In addition, there are a number of aspects of the MASS that may be present barriers to entry for new participants looking to provide FCAS.

As such, when reviewing the MASS, the Commission recommends that AEMO consider:

- the settings within the MASS, e.g. the standard frequency ramp rate in light of recent system developments
- the trade-off made between services with overlapping timeframes (i.e. fast and slow, and slow and delayed), especially for facilities seeking recognition of faster response capabilities
- the timeframes for each service provided under the MASS
- the metering and verification requirements, especially with respect to fast contingency services where 50ms resolution data is required which may be prohibitive to distributed energy resources.

These are explored in more detail below.

We also consider there may be value in the MASS providing participants with more context and transparency for the intentions of the MASS and the problem it is trying to address. This context would be able to assist new entrants to FCAS markets to understand the problem the market ancillary services are trying to resolve, and how FCAS markets value different services. This is discussed in section 4.7.

E.4.1 Settings within the MASS

There are some settings within the MASS that may warrant reconsideration through a review of the MASS.

323 AEMO, Market ancillary services specification, p. 25, July 2017.

324 AEMO, submission to draft report, p. 11; AEMO, Initial operation of the Hornsdale Power Reserve Battery Energy Storage System, April 2018.

Contingency FCAS is enabled 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.

The combination of the frequency dead band, reference frequency and the standard frequency ramp, alongside the technical capability of a facility to respond to a frequency disturbance, are used to determine the amount of FCAS that a participant could be enabled to provide.

This may limit the faster responses capable of being provided by technologies such as storage and, as a consequence, sets an enablement level below the installed capacity of these units. Whilst this may not have been an issue for traditional FCAS service providers, it may present more of an issue for newer FCAS providers.

In a review of the MASS, there should be consideration of whether these settings remain appropriate.

However, the frequency dead band and the reference frequency are set based upon the frequency operating standard. For this reason, these settings may not warrant reconsideration unless changes are made to the frequency operating standard.[325]

On the other hand, the standard frequency ramp could be revised through a review of the MASS. This ramp rate represents a rate of change of frequency following a typical credible contingency. The rate of change of frequency following a credible contingency is likely to become increasingly steep as the amount of inertia present in the power system reduces with reduced synchronous generation.

E.4.2 Trade-off between services

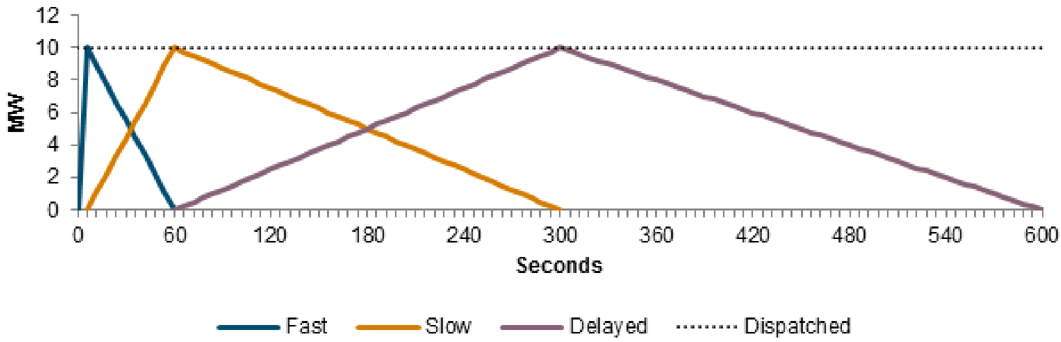
The current contingency services are fast, slow and delayed. These services are defined as the lesser of twice the time average of the response between:

- zero and six seconds, and six and 60 seconds for fast services
- six and 60 seconds, and 60 seconds and five minutes for slow services
- 60 seconds and five minutes, and five minutes and ten minutes for delayed services.

The classic response profile used to illustrate the application of the above approach is shown in Figure E.2 below.

325 The Reliability Panel is currently undertaking a review of the Frequency operating standard. The Panel is undertaking this review in a staged manner. The Panel published a final determination for stage one of this review on 14 November 2017 and intends to commence stage two following the publication of the Commission's final report for the Frequency control frameworks review. The Panel has indicated that stage two of the review of the Frequency operating standard will include consideration of the settings in the standard including the boundaries of the various frequency bands and the timeframes for restoration of power system frequency following specific events

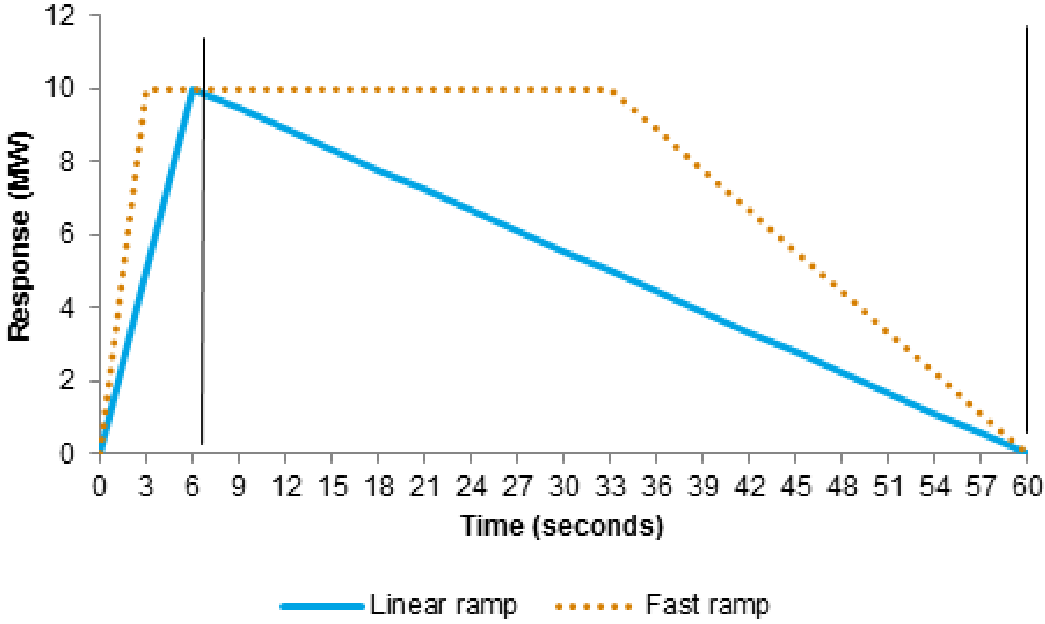
Figure E.2: Classic contingency response profile



This chart shows that for an idealised response where a FCAS provider ramps in a perfectly linear manner to a maximum of 10 MW, they will be registered (and potentially enabled) to provide 10 MW for each of the fast, slow and delayed services. This outcome reflects the principle that their response is symmetric and so is simply twice the time average of their response. In this example there is no complexity in the hand off between the different services and, at the time that the current FCAS frameworks were introduced, was probably fairly reflective of the prevailing capability of the generation fleet.

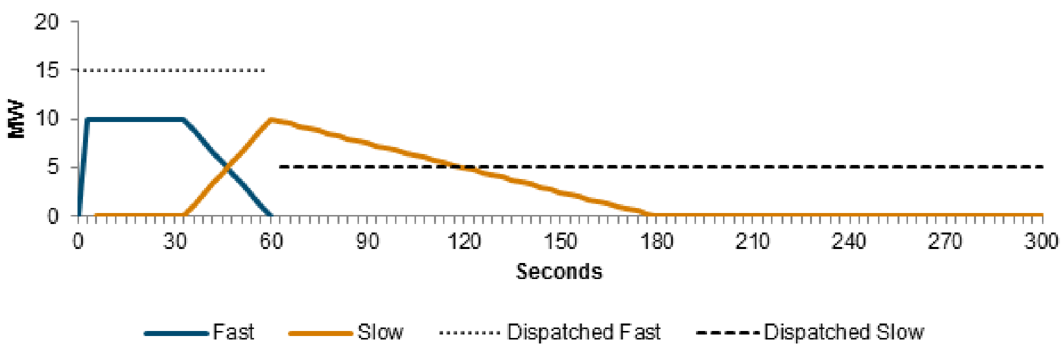
However, emerging technologies such as batteries have potentially very different response profiles, which may result in unintended negative incentives for these FCAS providers to participate in all FCAS markets. For example, the following chart shows a relatively fast ramp from a battery (the dotted line) for the first three seconds, which is compared against the conventional linear ramp (the solid line). In order for the battery to be appropriately compensated for its faster response in the first three seconds, it must maintain an equivalent response over the following period up to 60 seconds. This economically optimal response has the same time average value as the ramp up in the first six seconds and is shown in Figure E.3 below.

Figure E.3: Faster ramp compared to a linear ramp



However, such a sustained response profile reduces the response volume deemed available for the overlapping slow service as illustrated in Figure E.4.

Figure E.4: Providing more fast service reduces quantity of slow service provided



Critically, the current service specifications create an economic incentive for the FCAS provider to limit its slow service response profile in order to maximise its enablement level for fast FCAS. In the example above, the maximum enablement for the fast service is 15 MW, which is twice the time average response, shown by the blue line. However, the maximum enablement for the slow service is only 5 MW as a result of the need to slow the response profile up to 60 seconds, shown by the orange line. Both of these response profiles are consistent with the 10 MW facility capability but result in different levels of enablement.

This does not appear consistent with good market design principals in that the facility, in order to maximise its participation in the fast service, has had to reduce its enablement in the slow service. In the example above, if the FCAS provider were to sustain a response of 10 MW for longer than is shown in the blue line, it would be doing so for free.

The response trapeziums such as those illustrated in the above figures are the minimum performance and that in reality, most enabled facilities do not attempt to follow the economically optimum profile (that is, matching the minimum requirement shown above) but rather tend to continue to provide a frequency responsive service which in effect provides a service for free.

The trade-off between the fast and the slow service exists to prevent 'double dipping' where a participant may be enabled to provide the same response into two markets and effectively be paid twice for the same service.

There is a need for a trade-off between overlapping services under the current MASS. However, the assumption of a linear ramp up and down for each service may not reflect the characteristics of new technologies with greater controllability. Accounting for a non-linear response to frequency may allow greater value to be attained from frequency responsive new technologies. Therefore, there should consideration to how the overlap between services is treated through the MASS.

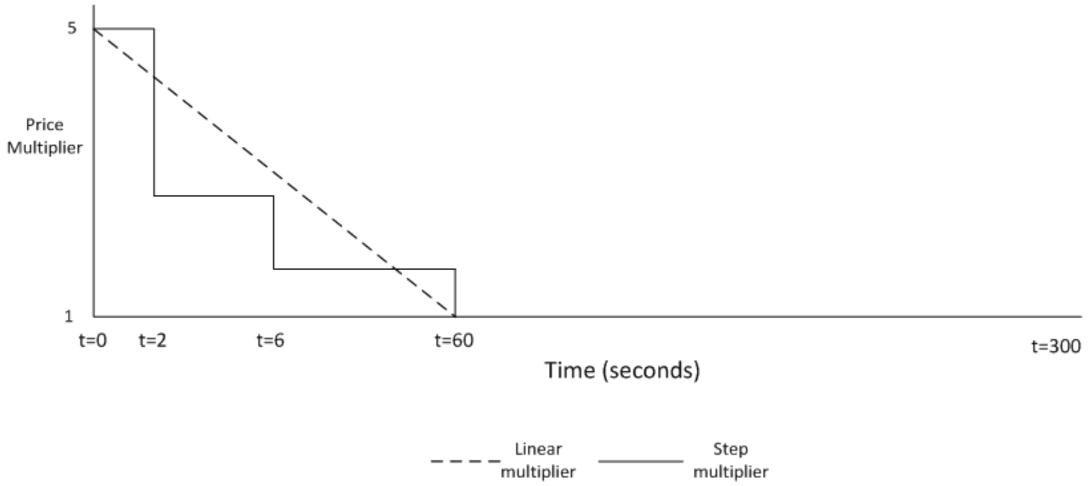
E.4.3 Time frames for each service

The response timeframes associated with each existing service within the MASS could be adjusted to account for different timeframes for the provision of frequency to the extent that this is found to be valuable.

For example, the fast service could be redesigned to accommodate wind farm based synthetic inertia which is likely to have a maximum sustain time of 10 or 12 seconds. This could involve redefining the fast contingency service as a response that ramps up within 3 seconds and ramps down within 12 seconds.

Alternatively, the definition of the 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 post contingency period (perhaps five minutes supported by a pricing structure that provides a premium for faster provision of the service). An example of how a price multiplier might be applied is provided in Figure E.5.

Figure E.5: Examples of possible price multipliers



The figure above provides an example of a linear price multiplier and a step function price multiplier which could be used in conjunction with an integral active power calculation approach to provide differential pricing across the response time frame of a contingency FCAS provider. What this would do is value a frequency response more, closer to the time of the disturbance, and at decreasing amounts in the time after the disturbance. This would provide greater value for fast responses and lesser value for slow responses.

The price multiplier would be known ahead of time with FCAS provider performance also being pre-defined. The multiplier could be specified so that the maximum price would not exceed the market price cap.

However, this would require substantial changes to the way AEMO currently enables FCAS. Currently, AEMO treats a MW of fast contingency FCAS equally between all participants that are register to provide it. By introducing a linear pricing function, AEMO would not necessarily be able to treat FCAS providers equally and would need to be more selective in the participants it enables to provide FCAS. This may also affect the technologically neutral manner in which AEMO selects participants to be enabled for FCAS.

Nonetheless, the review of the MASS provides a good opportunity for AEMO to consider, in consultation with industry, what the appropriate timeframes for the services within the MASS should be and whether they may need to change going forward.

E.4.4 Metering and verification requirements

Over the course of this review, stakeholders have noted that the requirements set out in the MASS require onerous levels of metering and verification that would be cost-prohibitive to extend to individual distributed energy resources.

The MASS does not specify a particular grade of metering as necessary to provide FCAS. Rather, it outlines the required capability of providers to measure and verify the extent of any service provided.

The draft report concluded that the MASS does not appear to impose onerous requirements in regard to the provision of regulating, slow and delayed services. However, high speed (50ms) measurement is needed for the provision of the fast (six second) contingency services.

Inherent in these requirements is a trade-off between the granularity of the measurement and verification data required, and the costs imposed on the provider. The balance that may have been appropriate when FCAS participants were large, thermal units may no longer be the case as increasing numbers of smaller generating units and loads participate in FCAS markets.

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, it may be necessary to consider whether these requirements will continue to be feasible and appropriate if they act as a barrier to the efficient provision of market ancillary services from 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.

Therefore, consistent with our position in the draft report, we consider that there is value in AEMO undertaking trials of distributed energy resources providing market ancillary services with a view to assessing different methods for metering and verifying a response. 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. It may also provide a means to test a certain proportion of an aggregator's portfolio and make assumptions about the remainder on that basis.

In its submission to the draft report, AEMO noted that it was seeking to trial aggregated distributed energy resources providing FCAS and suggested assessing how to balance the need to accurately assess service provision against the costs of specifications. One potential approach suggested by AEMO is the sampling across a set number of generating units with high speed monitoring and extrapolating that response across the remaining generating units with low speed metering.[326]

We agree that new approaches should be considered. We also consider that, in scoping these trials, AEMO should consider proposals from market participants as to how it can accurately assess the performance of an aggregated portfolio of distributed energy

326 AEMO, submission to draft report, p. 11.

resources. This could also be informed by the work that has been undertaken by ARENA to date on distributed energy resources.

In addition, we are working with AEMO to develop a joint work program on distributed energy resources, with the objective of better coordinating the various areas of work that both bodies are undertaking on related issues, which (as explained in section D.7) includes consideration of the technical and regulatory implications of virtual power plants. .

E.4.5 Communication with aggregated distributed energy resources

It is possible that there may be additional communication complexities associated with the provision of regulating FCAS from aggregated distributed energy resources.

Unlike contingency services that are triggered by a local measurement of frequency, regulating FCAS is dispatched centrally by AEMO on a regular basis through AGC. The use of AGC to control regulating services from distributed energy resources may be ineffective if the signals are unable to be received from AEMO within sufficient time for the response to be activated.

For large providers of regulating FCAS, the AGC 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, it is possible that these delays could be very minor (approximately one to two seconds) and not present a significant barrier for distributed energy resources providing regulating FCAS. There would still be a challenge for the aggregator would be to understand in real time the actual availability of the aggregated systems, their headroom and their ability to follow targets.

There would be value in assessing the challenges associated with communicating regulating FCAS signals to a distributed energy resource portfolio and whether there may be changes to communication protocols necessary. This could be addressed when trialing the capability of distributed energy resources to provide FCAS.

E.4.6 Issues raised in the previous review of the MASS

When AEMO last reviewed the MASS, a number of issues raised by stakeholders were considered out of scope. The review was primarily intended to account for the participation of Market Ancillary Service Providers. AEMO suggested the issues raised would be considered in a subsequent review of the MASS.

The issues raised included:

- The difference between a provider's frequency deviation setting[327] and the normal operating frequency band affecting the quantity of FCAS a participant may be able to provide. Where proportional providers of FCAS start providing FCAS as soon as the

327 The power system frequency at which a FCAS unit using a switched controller should provide FCAS.

frequency leaves the normal operating frequency band, a switched controller responds when frequency reaches a frequency deviation setting. As a result, the amount of response the participant can provide is:

  - between the frequency dead band and the reference frequency for a proportional controller
  - between the frequency deviation setting and the reference frequency for a switched provider which will be less than what a proportional controller would be able to provide.

- The potential for units providing regulating services to respond to local frequency measurements rather than the central AGC systems. It was suggested during the review that this might support the provision of regulating FCAS from an aggregated portfolio of loads.

AEMO considered these 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. While these issues were raised, we understand that not all of these issues were necessarily resolved.

We consider that these issues raised by stakeholders in the 2017 review remain relevant and, as with the balance of suggestions above, should being included in the scope of the upcoming MASS review.

E.4.7 More context within the MASS

The Commission considers there may be value in AEMO providing more of a ‘plain English’ explanation of the MASS and transparency regarding the assumptions that underpin the FCAS markets.

The current MASS provides for a range of services that seek to maintain power system frequency within acceptable bounds. However, it does not provide a clear articulation of the context for the need for these services. The Commission understands that the lack of context for the specification of different market ancillary services may be a cause of confusion amongst market participants.

FCAS markets are set up to place value on different services used to maintain frequency. These services are enabled to effectively provide insurance to the power system to protect against a frequency disturbance. The definition of the services enabled in FCAS markets place value according to different response profiles.

In designing these services, there is an assumption regarding the size of the frequency disturbance and the natural response of the power system to this disturbance.

The Commission considers there would be value in AEMO providing greater transparency to market participants regarding the nature of the problem the MASS is seeking to manage. This would assist in providing transparency and justification as to why FCAS markets value specific services, and why some response profiles are not considered valuable.

We also note that there are likely to be issues outside of the MASS that limit the ability for a participant to register capacity for FCAS. For example, there may be technical reasons why a network service provider might limit the droop curve of the proportional response. For example, if a participant were to have a very low droop curve setting, it is possible that this could have an adverse impact on network voltages. This would occur if a large, rapid injection of energy in response to a contingency event may cause voltages to exceed secure levels, particularly in weaker parts of the network.

To the extent that participants perceive there to be barriers within the MASS that actually pertain to technical limits on the response of a facility to preserve network stability, the MASS review would provide an opportunity for greater transparency regarding the relationship between the two.

E.5 Recommendation

This recommendation combines two recommendations made in the draft report: one that related to distributed energy resources providing FCAS; and one relating to long term development of FCAS frameworks.

The recommendation reflects the analysis undertakven by the Commission in respect of aspects of the MASS that may be worth considering by AEMO in a review.

RECOMMENDATION 7: MARKET ANCILLARY SERVICES SPECIFICATION

That AEMO:

1. undertake trials of distributed energy resources providing FCAS, including virtual power plants, 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 and incorporating the outcomes of the trials (and any other trials of new technologies providing FCAS) into a review of the MASS.
2. conduct a broader review of the MASS that seeks to address any unnecessary barriers to new entrants, or any aspects of the MASS that may not appropriately value services provided by newer technologies where these services are valuable to maintaining power system frequency. This should include consideration of:
    a. the timing specifications for each of the different FCAS
    b. the overlapping interactions between the different FCAS specifications
    c. any changes that may be necessary to settings within the MASS
    d. issues raised in the most recent review of the MASS that were considered out of scop

F PROPOSED RULE DRAFTING FOR AGGREGATOR REGULATORY FRAMEWORKS

CHAPTER 2

2. Registered Participants and Registration

2.3.5 Ancillary services load

(a) If a *Market Ancillary Service Provider* in respect of a *load*, or the *Market Customer* in respect of a *market load*, wishes to use that *load* or *market load* to provide *market ancillary services* in accordance with Chapter 3, then the *Market Ancillary Service Provider* or *Market Customer* (as the case may be) must apply to *AEMO* for approval to classify the *load* or *market load* as an *ancillary service load*.

(a1) For the avoidance of doubt a *Market Ancillary Service Provider* may apply, and *AEMO* may approve, the classification of a *load* as an *ancillary service load* where the relevant *market ancillary services* are provided partially or fully through the enablement of one or more *small generating units* that are electrically connected to a *retail customer's connection point* at a location that is on the same side of that *connection point* as the *metering point*.

(b) An application under paragraph (a) must be in the form prescribed by *AEMO* and:

(1) specify the *market ancillary services* which the *Market Ancillary Service Provider* in respect of a *load* or *Market Customer* in respect of a *market load* (as the case may be) wishes to provide using the relevant *load* or *market load;* and

(2) in the case of an application made by a *Market Ancillary Service Provider*, not be in respect of a *market load* that is a *scheduled load*.

(c) *AEMO* must, within 5 *business days* of receiving an application under paragraph (a), advise the applicant of any further information or clarification which is required in support of its application if, in *AEMO's* reasonable opinion, the application:

(1) is incomplete; or

(2) contains information upon which *AEMO* requires classification.

(d) If the further information or clarification required pursuant to paragraph (c) is not provided to *AEMO's* satisfaction within 15 *business days* of the request, then the *Market Ancillary Service Provider* or *Market Customer* (as applicable) will be deemed to have withdrawn the application.

(e) If *AEMO* is reasonably satisfied that:

(1) the *load* is able to be used to provide the *market ancillary services* referred to in the application in accordance with the *market ancillary service specification*;

(1A) the *Market Ancillary Service Provider* or the *Market Customer* (as the case may be) has an arrangement with the *retail customer* at the relevant *connection point* for the supply of *market ancillary services*; and

(2) the *Market Ancillary Service Provider* or the *Market Customer* (as the case may be) has adequate communications and/or telemetry to support the issuing of *dispatch instructions* and the audit of responses,

then *AEMO* must approve the classification in respect of the particular *market ancillary services*.

(f) If *AEMO* approves the classification of a *load* as an *ancillary service load*, then *AEMO* may impose on the relevant *Market Ancillary Service Provider* or *Market Customer* (as the case may be) such terms and conditions as *AEMO* considers necessary to ensure that the provisions of the *Rules* applying to *market ancillary services* can be met.

(g) A *Market Ancillary Service Provider* and *Market Customer* (as applicable):

(1) must comply with any terms and conditions imposed by *AEMO* under paragraph (f);

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(2) must ensure that the *market ancillary services* provided using the relevant *ancillary services load* are provided in accordance with the co-ordinated *central dispatch* process operated by *AEMO* under the provisions of Chapter 3 and in accordance with the *market ancillary service specification*;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(3) may submit to *AEMO market ancillary service offers* in respect of the *ancillary service load* in accordance with the provision of Chapter 3; and

(4) if the *Market Ancillary Service Provider* or *Market Customer* (as applicable) submits a *market ancillary service offer* in respect of the relevant *ancillary service load*, must comply with the *dispatch instructions* from *AEMO* in accordance with the *Rules*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(h) A *Market Ancillary Service Provider* or *Market Customer* (as applicable) with an *ancillary service load* must only sell the *market ancillary services* produced using that *ancillary service load* through the *spot market* in accordance with the provisions of Chapter 3.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(i) A *Market Ancillary Service Provider* or *Market Customer* (as applicable) is not entitled to receive payment from *AEMO* for *market ancillary services* except where those *market ancillary services* are produced using an *ancillary* *service load* in accordance with Chapter 3 or pursuant to a *direction* or *clause 4.8.9 instruction*.

(j) A *Market Ancillary Service Provider* and *Market Customer* (as applicable) must immediately notify *AEMO* if a *load* it has classified as an *ancillary service load* ceases to meet the requirements for classification under this clause 2.3.5.

2.3A Small Generation Aggregator

2.3A.1 Registration

(a) A person who intends to supply electricity from one or more *small generating units* to a *transmission or distribution system* may, upon application for registration by that person in accordance with rule 2.9, be registered by *AEMO* as a *Small Generation Aggregator*.

(b) To be eligible for registration as a *Small Generation Aggregator*, a person must satisfy *AEMO* that the person intends to classify, within a reasonable amount of time, one or more *small generating units* each as a *market generating unit*, with each *market generating unit* having a separate *connection point*.

(c) A person must not engage in the activity of selling electricity directly to the *market* at any *connection point*, unless that person is registered by *AEMO* as a *Market Participant* and that *connection point* is classified as one of that person's *market connection points*.

(d) A person must not classify a *small generating unit* as a *market generating unit* for electricity supplied from any *connection point* unless the person satisfies the requirements of the *participating jurisdiction* in which the *connection point* is situated so that (subject to compliance with the *Rules*) the person is permitted to supply electricity in the *spot market* in relation to that *connection point*.

(e) A *Market Small Generation Aggregator* must classify each *small generating unit* from which it proposes to supply electricity as a *market generating unit*, with each *market generating unit* having a separate *connection point*.

(e1) A *Market Small Generation Aggregator* may also classify one or more of its *small generating units* as an *ancillary service generating unit* where it has obtained the approval of *AEMO* to do so.

(f) A *Market Small Generation Aggregator's* activities only relate to *small generating units* it has classified as *market generating units* or *ancillary service generating units*, and only while it is also registered with *AEMO* as a *Small Generation Aggregator*.

(g) A *Market Small Generation Aggregator* must sell all *sent out generation* through the *spot market* and accept payments from *AEMO* for all *sent out generation* at the *spot price* applicable at the *connection point* for which it is *financially responsible* as determined for each *trading interval* in accordance with the provisions of Chapter 3.

(h) A *Market Small Generation Aggregator* must purchase all electricity *supplied* through the *national grid* to the *Market Small Generation*

Aggregator at that *connection point* from the *spot market* and make payments to *AEMO* for such electricity *supplied* at the *connection point* for which it is *financially responsible* as determined for each *trading interval* in accordance with the provisions of Chapter 3.

2.3A.2 Ancillary services generating unit

(a) If the *Market Small Generation Aggregator* in respect of one or more *small generating units* wishes to use the *small generating unit(s)* to provide *market ancillary services* in accordance with Chapter 3, then the *Market Small Generation Aggregator* must apply to *AEMO* for approval to classify the *generating unit(s)* as one or more *ancillary service generating units*.

(b) At the time that a *Market Small Generation Aggregator* makes a request to *AEMO* under paragraph (a), the *Market Small Generation Aggregator* may request to register two or more *small generating units* as one *ancillary service generating unit*.

(c) An application under paragraph (a) must be in the form prescribed by *AEMO* and specify the *market ancillary services* which the *Market Small Generation Aggregator* wishes to provide using the relevant *small generating unit(s)*.

(d) *AEMO* must, within 5 *business days* of receiving an application under paragraph (a), advise the applicant of any further information or clarification which is required in support of its application if, in *AEMO's* reasonable opinion, the application:

(1) is incomplete; or

(2) contains information upon which *AEMO* requires clarification.

(e) If the further information or clarification required pursuant to paragraph (d) is not provided to *AEMO's* satisfaction within 15 *business days* of the request, then the *Market Small Generation Aggregator* will be deemed to have withdrawn the application.

(f) If *AEMO* is reasonably satisfied that:

(1) the *small generating unit(s)* is/are able to be used to provide the *market ancillary services* referred to in the application in accordance with the *market ancillary service specification*; and

(2) the *Market Small Generation Aggregator* has adequate communication and/or telemetry to support the issuing of *dispatch instructions* and the audit of responses,

then *AEMO* must approve the classification in respect of the particular *market ancillary services*.

(g) If *AEMO* approves the classification of one or more *small generating units* as an *ancillary service generating unit*, then *AEMO* may impose on the relevant *Market Small Generation Aggregator* such terms and conditions as *AEMO* considers necessary to ensure that the provisions of the *Rules* applying to *market ancillary services* can be met.

(h) A *Market Small Generation Aggregator*:

(1) must comply with any terms and conditions imposed by *AEMO* under paragraph (g);

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision under the National Electricity (South Australia) Regulations.

(2) must ensure that the *market ancillary services* provided using the relevant *ancillary service generating unit* are provided in accordance with the co-ordinated *central dispatch* process operated by *AEMO* under the provisions of Chapter 3 and in accordance with the *market ancillary service specification*;

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision under the National Electricity (South Australia) Regulations.)

(3) may submit to *AEMO market ancillary service offers* in respect of the *ancillary service generating unit* in accordance with the provisions of Chapter 3; and

(4) if the *Market Small Generation Aggregator* submits a *market ancillary service offer* in respect of the relevant *ancillary service generating unit*, must comply with the *dispatch instructions* from *AEMO* in accordance with the *Rules*.

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision under the National Electricity (South Australia) Regulations.)

(i) A *Market Small Generation Aggregator* with an *ancillary service generating unit* must only sell the *market ancillary services* produced using that *ancillary service generating unit* through the *spot market* in accordance with the provisions of Chapter 3.

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision under the National Electricity (South Australia) Regulations.)

(j) A *Market Small Generation Aggregator* is not entitled to receive payment from *AEMO* for *market ancillary services* except where those *market ancillary services* are produced using an *ancillary service generating unit* in accordance with Chapter 3 or pursuant to a *direction* or *clause 4.8.9 instruction*.

2.3AA Market Ancillary Service Provider

2.3AA.1 Registration

(a) A person must not engage in the activity of offering and providing *market ancillary services* in accordance with Chapter 3 as a *Market Ancillary Service Provider* unless that person is registered by *AEMO* as a *Market Ancillary Service Provider*.

(b) To be eligible for registration as a *Market Ancillary Service Provider*, a person must:

(1) obtain the approval of *AEMO* to classify *load connected* to a *transmission or distribution system* that it wishes to use to provide *market ancillary services* by:

(i) identifying units of *load* (and any *small generating units* electrically connected to that *load*) under its ownership, operation or control;

(ii) demonstrating how *load* (and any *small generating units* electrically connected to that *load*) identified in (i) are under its ownership, operation or control; and

(iii) demonstrating that the *load* (and any *small generating units* electrically connected to that *load*) identified in (i) have the required equipment to be used to provide *market ancillary services*;

(2) satisfy *AEMO* that each *load* (and any *small generating units* electrically connected to that *load*) referred to in subparagraph (1) will be capable of meeting or exceeding the relevant *performance standards* and specifications to *AEMO*'s satisfaction.

(c) A *Market Ancillary Service Provider* may classify the *load* referred to in subparagraph (b)(1) as an *ancillary service load* in accordance with clause 2.3.5 where it has obtained the approval of *AEMO* to do so.

(d) A *Market Ancillary Service Provider*'s activities only relate to *loads* it has classified (in its capacity as a *Market Ancillary Service Provider*) as *ancillary service loads*, and only while it is also registered with *AEMO* as a *Market Ancillary Service Provider*.

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2.12 Interpretation of References to Various Registered Participants

(a) A person may register in more than one of the categories of *Registered Participant*.

(b) Notwithstanding anything else in the *Rules*, a reference to:

(1) a "*Generator*" applies to a person registered as a *Generator* only in so far as it is applicable to matters connected with the person's *scheduled generating units*, *semi-scheduled generating units*, *non-scheduled generating units*, *market generating units* or *non-market generating units*;

(1A) a "*Small Generation Aggregator*" applies to a person registered as a "*Small Generation Aggregator*" only in so far as it is applicable to matters connected with the person's *small generating units* or *market generating units*;

(1B) a "*Market Ancillary Service Provider*" applies to a person registered as a "*Market Ancillary Service Provider*" only in so far as it is applicable to matters connected with the person's *ancillary service load*;

(2) a "*Scheduled Generator*", "*Semi-Scheduled Generator*", "*Non-Scheduled Generator*", "*Market Generator*" or "*Non-Market*

Generator" applies to a person only in so far as it is applicable to matters connected with the person's *scheduled generating units*, *semi-scheduled generating units*, *non-scheduled generating units*, *market generating units* or *non-market generating units* respectively;

(3) a "*Customer*" applies to a person registered as a *Customer* only in so far as it is applicable to matters connected with the person's *first-tier loads*, *second-tier loads* or *market loads*;

(4) a "*First Tier Customer*", "*Second Tier Customer*" or "*Market Customer*" applies to a person only in so far as it is applicable to matters connected with the person's *first-tier loads*, *second-tier loads* or *market loads* respectively;

(4A) a "*Trader*" applies to a person only in so far as it is applicable to matters connected with the person's activities as a *Trader*;

(4B) a "*Reallocator*" applies to a person only in so far as it is applicable to matters connected with the person's activities as a *Reallocator*;

(5) a "*Network Service Provider*" applies to a person registered as a *Network Service Provider* only in so far as it is applicable to matters connected with the person's *network services*, including *market network services* and *scheduled network services*;

(6) a "*Market Network Service Provider*" or "*Scheduled Network Service Provider*" applies to a person only in so far as it is applicable to matters connected with the person's *market network services* or *scheduled network services* respectively;

(7) a "*Market Participant*" applies to a person who is a *Market Participant* and:

   (i) where that person is registered as a *Market Generator*, in so far as it is applicable to matters connected with the person's *market generating units* or *ancillary services generating units*; and

   (i1) where that person is registered as a *Market Small Generation Aggregator*, in so far as it is applicable to matters connected with the person's *market generating units* or *ancillary service generating units*; and

   (i2) where that person is registered as a *Market Ancillary Service Provider*, in so far as it is applicable to matters connected with the person's *ancillary service load*; and

   (ii) where that person is registered as a *Market Customer*, in so far as it is applicable to matters connected with the person's *market loads* or *market ancillary service loads*; and

   (iii) where that person is registered as a *Market Network Service Provider*, in so far as it is applicable to matters connected with the person's *market network services*; and

   (iv) where that person is registered in any category of *Market Participant* additional to a *Market Generator* and/or a *Market Customer* and/or a *Market Network Service Provider*, to the extent to which the reference would otherwise apply to the person if it were not taken to be a *Market Generator*, *Market Customer* or *Market Network Service Provider*; and

(8) a "*Registered Participant*" applies to a person who is registered under Chapter 2 and:

(i) where that person is registered as a *Generator*, in so far as it is applicable to matters connected with any of the *Generator's scheduled generating units*, *semi-scheduled generating units*, *non-scheduled generating units*, *market generating units* and *non-market generating units*;

(ii) where that person is registered as a *Customer*, in so far as it is applicable to matters connected with any of the *Customer's first-tier loads*, *second-tier loads* or *market loads*; and

(iii) where that person is registered in any other *Registered Participant* category, to the extent to which the reference would apply to the person if it were not registered in another *Registered Participant* category.

(c) In rule 2.12, "*matter*" includes any assets, liabilities, acts, omissions or operations (whether past, present or future).

CHAPTER 3

3. Market Rules

3.8 Central Dispatch and Spot Market Operation

3.8.3 Bid and offer aggregation guidelines

(a) *Scheduled Generators*, *Semi-Scheduled Generators* or *Market Participants* who wish to aggregate their relevant *generating units*, *scheduled network services* or *scheduled loads* for the purpose of *central dispatch* must apply to *AEMO* to do so.

(a1) *Market Customers* or *Market Ancillary Service Providers* (as applicable) who wish to aggregate two or more *loads* so they are treated as one *ancillary service load* for the purpose of *central dispatch*, must apply to *AEMO* to do so.

(a2) *Market Small Generation Aggregators* who wish to aggregate two or more *small generating units* so they are treated as one *ancillary service generating unit* for the purpose of *central dispatch*, must apply to *AEMO* to do so.

(b) *AEMO* must approve applications for aggregation made under paragraph (a) if the following conditions are fulfilled:

(1) aggregated *generating units* or *loads* must be:

(i) *connected* at a single site with the same *intra-regional loss factor* or, if two *intra-regional loss factors* are determined for the site under clause 3.6.2(b)(2), the same two *intra-regional loss factors*; and

(ii) operated by a single *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant*;

(2) aggregated *scheduled network services* must be *connected* at the same two sites, have the same *intra-regional loss factors*, have the same *distribution loss factors* where applicable and be operated by the same *Generator* or *Market Participant*;

(3) *power system security* must not be materially affected by the proposed aggregation; and

(4) *control systems* such as *automatic generation control systems* must satisfy the *Rules* after aggregating.

(b1) *AEMO* must approve applications for aggregation made under paragraph (a1) if the following conditions are fulfilled:

(1) aggregated *ancillary services loads* must be *connected* within a single *region* and be operated by a single person (whether in its capacity as a *Market Customer*, *Market Ancillary Service Provider* or both);

(2) *power system security* must not be materially affected by the proposed aggregation; and

(3) *control systems* must satisfy the requirements of clause 2.3.5(e)(1) and (2) after aggregating.

(b2) *AEMO* must approve applications for aggregation made under paragraph (a2) if the following conditions are fulfilled:

(1) aggregated *ancillary service generating units* must be *connected* within a single *region* and be operated by a single *Market Small Generation Aggregator*;

(2) *power system security* must not be materially affected by the proposed aggregation; and

(3) *control systems* must satisfy the requirements of clause 2.3.A.2(f)(1) and (2) in relation to a *Market Small Generation Aggregator* after aggregating.

(c) Notwithstanding that one or more of the conditions set out in paragraph (b) may not have been fulfilled by the *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant*, *AEMO* may approve an application for aggregation provided that such aggregation would not materially distort *central dispatch*.

(d) Subject to paragraph (f), for the purposes of Chapter 3 (except rule 3.7B) and rule 4.9, a reference to a *generating unit*, *scheduled load* and *scheduled network service* is only taken as a reference to aggregated *generating units*, aggregated *scheduled network services* and aggregated *scheduled loads* aggregated in accordance with this clause 3.8.3.

(e) *AEMO* must evaluate applications for aggregation and reply within 20 *business days* of receipt of the application setting out whether the application is to be approved and the conditions that apply to the proposed approval.

(f) *Scheduled Generators* and *Market Participants* that have been granted aggregated status must, if required by *AEMO*, declare individual *scheduled generating unit*, *scheduled network service* or *scheduled load* availability and operating status to *AEMO* in the *PASA* process under rule 3.7 to allow *power system security* to be effectively monitored.

(g) If a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant's* application for aggregation is denied by *AEMO*, *AEMO* must provide that applicant with reasons for that denial.

(h) *AEMO* must maintain a database of aggregated *scheduled generating units*, *semi-scheduled generating units*, *scheduled network services*, *scheduled loads*, *ancillary service generating units* and *ancillary services loads* and their components.

(i) For the avoidance of doubt, *semi-scheduled generating units* which are registered as a single *semi-scheduled generating unit* under clause 2.2.7 are not aggregated *semi-scheduled generating units* for the purposes of Chapter 3 and rule 4.9.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commisison	See AEMC
FCAS	Frequency control ancillary services
FFR	Fast frequency response
FI	Frequency indicator
MASS	Market ancillary services specification
NEL	National Electricity Law
NEO	National electricity objective

TERMINOLOGY

The following terms are used often in Appendices A and B, or are related to the subject matter of those appendices.

Table 3: **Terminology in this report**

TERM	MEANING
Frequency indicator (FI)	A parameter used within AEMO's systems to indicate the extent to which more generation (in which case it is positive) or less generation (negative) is required to restore the frequency to 50 Hz. The sign of FI indicates which FCAS (raise or lower) is required at any given time.
Frequency regulation	The management of frequency during normal operation (in the absence of a contingency event) within the normal operating frequency band.
Frequency response	A change in active power from a generator or load related to the management of the power system frequency.
Market ancillary services	The market ancillary services are set out in clause 3.11.2 of the NER. They include the six contingency services and the two regulation services.
Normal operating frequency band	The normal operating frequency band defined in the frequency operating standard – 49.85Hz – 50.15 Hz.
Primary frequency control	A frequency response that is fast acting, continuous and proportional to the locally measured frequency.
Primary frequency response	The actual change in active power related to the provision of primary frequency control. This include a primary frequency response for the purpose of contingency management or for frequency regulation within the normal operating frequency band.
Primary regulating response	A primary frequency response for the purpose of frequency regulation.
Primary regulating service	A service for the provision of primary regulating response.
Regulating raise service	A FCAS that provides for secondary frequency control in accordance with electronic signals from AEMO to raise the frequency of the power system. This is a term defined in Chapter 10 of the NER.
Regulating lower service	A FCAS that provides for secondary frequency control in accordance with electronic signals from AEMO to lower the

TERM	MEANING
	frequency of the power system. This is a term defined in Chapter 10 of the NER.
Regulation services	Both the regulating raise service and the regulating lower service. This is a term defined in chapter 10 of the NER.
Secondary frequency control	A frequency response delivered in response to a control signal based on the centralised measurement of frequency, this type of control is slower acting than primary frequency control and is intended to be sustained.