Fast Frequency Response Implementation Options

April 2021

Technical advice on the development of FFR arrangements in the NEM

Important notice

PURPOSE

This report provides general and technical information and analysis on potential development options for Fast Frequency Response (FFR) services in the National Electricity Market, to help inform the Australian Energy Market Commission in its consideration of proposed changes to the National Electricity Rules.

This report has been prepared using information available to AEMO as at 26 February 2021.

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VERSION CONTROL

Version	Release date	Changes
1	13/4/2021	

Executive summary

There are currently two ongoing regulatory processes concerned with developing fast frequency response (FFR) services in the National Electricity Market (NEM):

- The Energy Security Board's (ESB's) Essential System Services Post 2025 Market Design initiative[1] includes FFR as potential new service[2].
- The Australian Energy Market Commission (AEMC) is progressing a proposed rule change, *Fast frequency response market ancillary service (ERC0296)*[3], which was submitted by Infigen Energy in July 2020, and is due for draft determination on 22 April 2021.

Specific scope items for this report have been agreed with the AEMC, as outlined in Appendix A1. The AEMC's Frequency Control Rule Change Directions Paper[4] (Directions Paper) outlines a range of options for the implementation of FFR in the NEM. These include:

- Introducing new market ancillary services to procure FFR frequency control ancillary services (FCAS).
- Reconfiguration of the existing FCAS arrangements to procure FFR.
- The use of differential pricing enabled through the application of scaling factors that reflect varying levels of performance from individual providers.

The content of this report is intended to provide technical advice on the physical system requirements underpinning the need for FFR. For a range of proposed solutions, the report aims to outline the ability of solution to meet the physical system requirements, and any implementation considerations from AEMO's perspective as a market and system operator.

The contents of this report build on the work AEMO has undertaken over many years in studying the applications and limitations of FFR in the context of the NEM.

The key recommendations are outlined in Table 1 below.

[1] ESB web page, *All about the post 2025 project*, at https://esb-post2025-market-design.aemc.gov.au/all-about-2025#what-happens-next. Viewed 1 March 2021.

[2] FTI Consulting report for the ESB, *Essential System Services in the National Electricity Market*, August 2020, at https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf.

[3] See https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

[4] At https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

Table 1 Summary of recommendations

Topic	Recommendation
1. Utility of FFR	**FFR services should be developed for managing frequency containment under system intact conditions.** In the longer term, use of existing services at greater volumes will be an inefficient way to ensure the required speed of frequency response under lower inertia conditions. Introduction of FCAS-like FFR services would recognise the existing speed capability within current FCAS provider facilities, as well as allowing new providers to enter the market to assist in reducing 6-second raise (R6)/6-second lower (L6) volume requirements. The introduction of an FFR FCAS may also allow for improvements to the arrangements already in place for use of FFR for the management of islanded regions.
2. Transitional arrangements	**Out of market arrangements should be considered as a transitional measure.** The use of out of market procurement as a transitional measure would allow the service specification to be more readily refined in advance of market implementation. Coupled with locational requirements, it would also help minimise the technical integration challenges and allow procedures to be developed to manage these challenges in the initial stages of the market.
3. Enduring arrangements	**FFR services, as an extension to FCAS, are suited to 5-minute markets in the longer term.** Provided locational limits and requirements can be managed in 5-minute markets, FFR can be implemented in these markets. The market impacts of these requirements should be considered in market design.
4. Reconfiguration of existing FCAS	**Market participants should be consulted on combining 6-second and 60-second services.** From a market systems implementation perspective, reconfiguration of the existing contingency FCAS arrangements to procure FFR, keeping three raise and three lower services, is preferable to introducing new services. It also results in simpler ongoing arrangements. Combining 6-second and 60-second raise services in parallel to introducing raise and lower FFR services would allow for this reconfiguration. There is a significant level of use of 6-second and 60-second services that would be affected by consolidating these services, and market participants should be further consulted on this potential change.
5. Scaling factors/ differential pricing	**Introduction of speed factor parameterisation is not recommended at this time.** Speed factor parametrisation of FCAS provision would require significant development in the NEM context. The application of this approach in the NEM may not provide the transparency of market outcomes that other approaches could provide, or provide clear signals on the required speed of response.
6. Interaction with inertia	**Inertia and FFR should not be combined within the same service.** Inertia and FFR both provide a valuable response, however, they are fundamentally different and should not be combined within the same service.

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1. Introduction

1.1 Purpose

The purpose of this report is to provide general information on the feasibility of different development options for fast frequency response (FFR) services in the National Electricity Market (NEM) and provide technical input to the ongoing regulatory reforms in the area of FFR.

There are currently two ongoing regulatory processes concerned with developing FFR services. These are:

- The Energy Security Board's (ESB's) Essential System Services Post 2025 Market Design initiative[5], which includes FFR as a potential new service[6].
- The *Fast frequency response market ancillary service (ERC0296)*[7] rule change, which was submitted by Infigen Energy in July 2020, and is being progressed by the Australian Energy Market Commission (AEMC).

Specific scope items for this report, agreed with the AEMC, are outlined in Appendix A1. The content of this report is intended to:

- Provide technical advice on the physical system requirements underpinning the need for FFR.
- For a range of proposed solutions, outline:
  - The ability of each to meet the physical system requirements.
  - The practical and technical implementation considerations of each, from AEMO's perspective as market and system operator.

This advice is not intended to provide a detailed service specification for FFR or fully develop how the market systems and associated processes would facilitate FFR. This advice is separate to and independent of any regulatory submission AEMO may make to the AEMC as part of the rule change process.

AEMO's *Frequency Control Workplan*[8] provides further context to this advice, with information on related work in the area of frequency control. This advice satisfies the deliverables listed under Task 9 of the *Frequency Control Workplan*.

1.2 Related publications

AEMO has previously produced publications relevant to FFR. These resources provide an overview of technical definitions, technology capabilities, and system needs and uses for FFR type services, and are summarised in Table 2.

[5] ESB web page, All about the post 2025 project, at https://esb-post2025-market-design.aemc.gov.au/all-about-2025#what-happens-next. Viewed 26 February 2021.

[6] FTI Consulting report for the ESB, Essential System Services in the National Electricity Market, August 2020, at https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf.

[7] See https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

[8] At https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

Table 2 Related resources

Resource	Summary	URL
International Review of Frequency Control Adaptation **(DGA Consulting; 2016)**	International experiences adapting frequency control measures.	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2016/fpss-international-review-of-frequency-control.pdf?la=en
Fast Frequency Response in the NEM – Working Paper **(2017)**	Provides information about possible applications of FFR services to complement existing frequency control.	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-working-paper.pdf
Advisory on equipment limits associated with high RoCoF **(GE Consulting; 2017)**	Explores the behaviour and vulnerability of equipment to a high rate of change of frequency (RoCoF). The focus of the paper is on behaviour of a variety of equipment in the power system that has the potential to adversely affect the resilience or robustness of the power system.	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/20170904-ge-rocof-advisory.pdf?la=en
Technology capabilities for fast frequency response **(GE Consulting, 2017)**	AEMO engaged GE Consulting to explore the potential value of a FFR service in the NEM and to provide advice on how such a service should be implemented.	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/20170310-ge-ffr-advisory-report.pdf?la=en
Fast Frequency Response Specification **(GE Energy Consulting Report Coversheet, 2017)**	Summarises AEMO's interpretation and intended next steps from GE's consulting report on the Technical Capabilities for FFR (above).	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-coversheet-20170310.pdf?la=en
Inertia Requirements Methodology ***Inertia Requirements and Shortfalls (2018)***	Contains the inertia requirements methodology and outlines the use of FFR in managing frequency containment for islanded regions,	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf
Minimum operational demand thresholds in South Australia **(2020)**	Summarises the results of AEMO's preliminary investigation into minimum operational demand levels in South Australia, in response to a request for information from the South Australian Government. It demonstrates the considerable value of FFR, including its current uses in frequency control in South Australia and as a component of emergency frequency response schemes.	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review
Notice of South Australia Inertia Requirements and Shortfall **(2020)**	Determination of an inertia shortfall in South Australia. This report accounts for the existing FFR available to support the South Australian network, and specifically considers how additional FFR capability can reduce inertia requirements for the region.	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F
Renewable Integration Study Stage 1 Appendix B: Frequency control **(2020)**	Explores potential system security limits that may arise as the proportion of wind and solar generation increases and highlights initial actions to address limitations. In particular, the decline in primary frequency response and reduction in inertia levels are explored.	https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en
Power System Requirements Paper **(2020)**	Provides information about the technical and operational requirements of the power system, including frequency control.	https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

1.3 Problem definition

Under low inertia conditions, larger volumes of Fast Raise (R6), as well as Fast Lower (L6) will be needed to manage frequency containment for credible events under system intact conditions, recognising that provision of response faster than the R6/L6 requirements will reduce the volumes of R6/L6 required and is likely to provide a more efficient mix of frequency control ancillary services (FCAS)-type products under projected levels of inertia.

To analyse the options available to procure FFR, the technical gap the service is aiming to fill must first be described. This section outlines where FFR is currently used in the NEM, and where there is opportunity to make future use of FFR. The section concludes with a problem definition for FFR service development.

1.3.1 Existing FFR applications

Minimum inertia requirements

The Minimum Inertia Requirements[9] set the minimum inertia values required to operate each NEM region under islanded conditions (Secure operating level of inertia), or when there is a credible risk of islanding (Minimum threshold level of inertia). AEMO will declare an inertia shortfall if the level of inertia over the forecast period falls below these minimum requirements. AEMO can agree adjustments to these levels if approved inertia support activities (such as the provision of FFR) will result in lower levels of synchronous inertia requirements[10].

The 2020 *Notice of South Australia Inertia Requirements and Shortfall*[11] identified the need for FFR to assist in supporting the security of South Australia when islanded. This assessment accounted for the existing FFR available to support the South Australian network, and identified how additional FFR capability could reduce inertia requirements for the region. In this case, it would not have been feasible to procure the quantity of inertia network services that would have been required from available sources without that additional FFR capability.

South Australian arrangements

FFR-type responses play an important role in the management of power system security in South Australia, in addition to the provisions outlined above. For example:

- FFR is important to the security of South Australia and is considered in the formulation of security constraints for managing separation events[12,13].
- The South Australian government has procured 70 megawatts (MW) of FFR to be available to assist in maintaining system security[14] as part of the Hornsdale Power Reserve (HPR) project[15].

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[9] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[10] Refer to NER 5.20B.5.

[11] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F.

[12] AEMO, Factsheet, *Heywood UFLS constraints*, October 2020, at https://www.aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en.

[13] AEMO, Advice prepared for the South Australian Government, *Minimum operating demand thresholds in South Australia*, May 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

[14] AEMO, *Notice of South Australia Inertia Requirements and Shortfall*, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F, see Section 2.3.2 *Role of fast frequency response.*

[15] See https://hornsdalepowerreserve.com.au/wp-content/uploads/2020/09/Aurecon-Economic-Assessment-Report-HPR.pdf.

- In September 2020, HPR and the South Australian Government agreed to increase the capacity reservation for HPR to 130 MW (and 32.5 megawatt hours [MWh] of energy storage) during any South Australia islanding event[16].
- The Office of the Technical Regulator (OTR) has published requirements for connecting generators in South Australia to be capable of providing inertia or FFR[17].

1.3.2 Proposed new FFR applications

FFR is not currently included in the suite of contingency FCAS, or otherwise sourced for explicit use under system intact conditions.

Both the ESB's *Essential System Services Post 2025 Market Design initiative*[18] and AEMC rule change on a *Fast frequency response market ancillary service (ERC0296)*[19] have identified the potential use of FFR as an extension of the existing contingency FCAS services.

The *Fast frequency response market ancillary service* rule change proposal[20] identified two uses for this additional service:

- Managing frequency containment for credible events.
- Managing rate of change of frequency (RoCoF).

Both suggested needs are discussed below.

Managing frequency containment for credible events

Currently, the volume of contingency FCAS is set based on the size of the Largest Credible Risk (LCR) less the expected amount of load relief for system intact. This produces the static requirement for contingency FCAS, which is a minimum requirement independent of system dynamics. For islanded conditions, a more complex method of determining FCAS volumes is used, taking inertia into consideration.

The static requirement for FCAS volumes was suited to the system conditions at the time of the original FCAS market design. Subsequent changes in system conditions, including increasing risk size and reduction in load relief and inertia, mean the static requirement for FCAS volumes is not suited to the system needs for system intact conditions into the future.

AEMO has determined there is a need to extend inertia-dependent FCAS volumes to system intact conditions. This work is set to commence in Q4 2021[21].

Should this change be introduced without an FFR service, greater volumes of R6/L6 FCAS would have to be purchased under lower inertia conditions.

Static requirement

The static requirement is the size of the LCR less the expected load relief.

When the active power lost during an event is replaced by an equal amount of active power (the static requirement), the frequency decline will be arrested.

As the static requirement accounts for load relief, it increases at low load. However, it does not account for the full dynamic effects of load relief and inertia.

[16] AEMO, *2020 System Strength and Inertia Report*, December 2020, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

[17] OTR, Generator Development Approval Procedure, effective 1 July 2017, at https://www.sa.gov.au/__data/assets/pdf_file/0003/311448/Generator-development-approval-procedure-V1.1.pdf

[18] At https://esb-post2025-market-design.aemc.gov.au/all-about-2025#what-happens-next.

[19] See https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

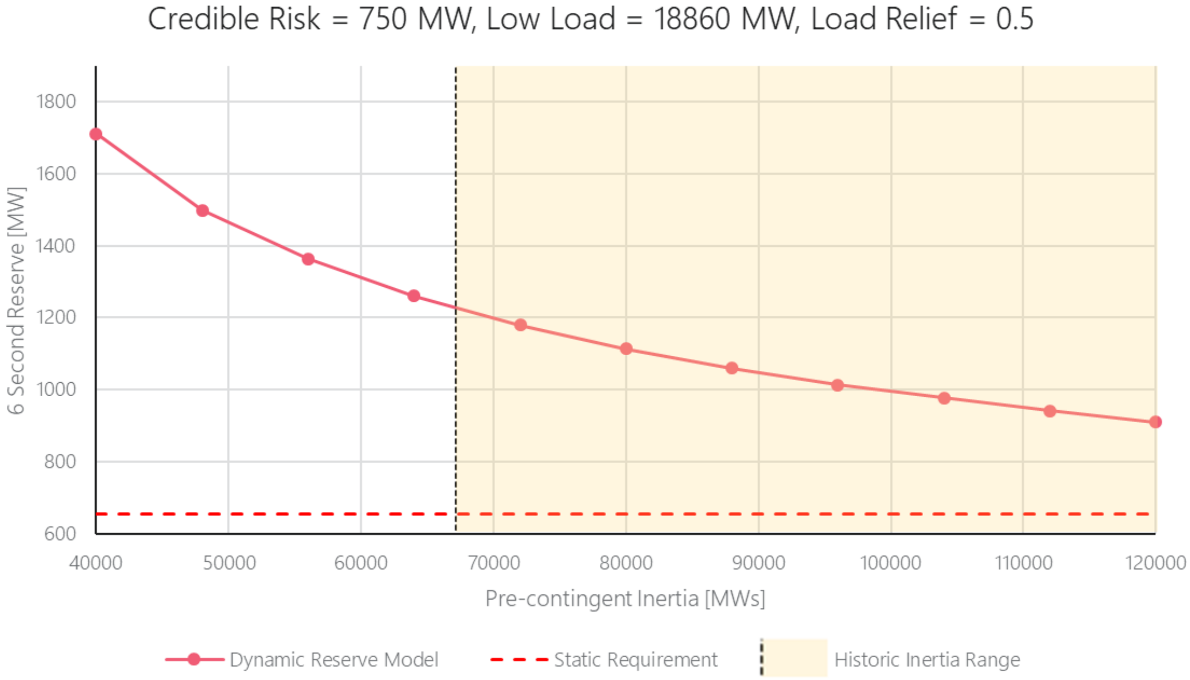
[20] At https://www.aemc.gov.au/sites/default/files/2020-03/ERC0296%20Rule%20change%20request.pdf.

[21] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-control-work-plan.

Figure 1 shows an indicative relationship between inertia and R6 under one specific load condition, risk, and assumed FCAS provider performance[22].

Extending inertia-dependent R6/L6 volumes to system intact conditions will ensure that the frequency containment criteria[23] continue to be met under lower inertia operating conditions. However, the R6/L6 services may not be the most efficient specification for frequency responsive reserve, as less reserve is needed under low inertia conditions if a proportion of it can be provided faster than the R6 specification[24].

Figure 1 Indicative relationship between NEM mainland inertia and R6 volume requirements



Managing rate of change of frequency

Islanded regions

The Minimum Inertia Requirements[25] address frequency containment for islanded regions or regions at risk of islanding. The use of FFR is permitted under the rules to assist with this task (as an inertia support activity).

Tasmania always operates as a synchronous island because it has no alternating current (AC) connection to the mainland NEM. The credible trip of its high voltage direct current (HVDC) connection to Victoria (Basslink) will leave Tasmania entirely isolated from the mainland NEM. Due to these unique circumstances, Tasmania has different requirements for managing frequency than the mainland NEM.

Security constraints also assist with RoCoF management. For example, in Tasmania, the size of the largest single infeed is managed to avoid triggering under-frequency load shedding (UFLS) on the RoCoF element. In

[22] This chart is based in indicative modelling and is a simplified view of requirements; see *Renewable Integration Study Stage 1 Appendix B: Frequency control*, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en. Constraint equations used for setting inertia dependent FCAS volumes are yet to be derived, and these may vary from the indictive chart based on further studies and practical considerations.

[23] AEMC, Frequency Operating Standard (FOS), at https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

[24] AEMO *Renewable Integration Study Stage 1 Appendix B: Frequency control*, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

[25] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

South Australia, flows on the Heywood interconnector are managed to limit RoCoF in South Australia for credible and non-credible separations.

System intact conditions (mainland)

Currently, it is estimated that the instantaneous RoCoF for the intact NEM mainland will remain within 0.5 hertz per second (Hz/s)[26], which is less than what islanded regions can experience currently and is within the manageable range as seen from international experience[27]. While RoCoF needs to be managed, directly managing instantaneous RoCoF to keep it above a minimum level is not currently required for system intact conditions. A more direct and immediate need for FFR is the efficient management of the containment criteria for credible events.

While there is a relationship between RoCoF and the required speed of FCAS services, there is also a need to manage the progression to lower inertia and higher RoCoF levels for system intact[28]. These issues are addressed further in Section 3.4.2.

1.3.3 Problem definition for FFR service development

Under low inertia conditions, larger volumes of fast raise (R6), as well as fast lower (L6), will be needed to manage frequency containment for credible events under system intact conditions. Recognising provision of response faster than the R6/L6 requirements will reduce the volumes of R6/L6 required and is likely to provide a more efficient mix of FCAS-type products under projected levels of inertia.

This problem definition is consistent with the problem definition and reform objective outlined in the AEMC's Directions Paper.

While the current rules allow for the use of FFR in managing islanded regions through the minimum inertia arrangements, market arrangements for FFR could also assist in managing islanded regions. This is discussed in Section 3.5.

[26] For the mainland NEM, if inertia were to decline to the level that would be maintained by the current set of synchronous units that must be online to support strength (~45,350 MWs), then with the current risk size, the instantaneous RoCoF will remain within 0.5 Hz/s.

[27] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/future-energy-systems/2019/aemo-ris-international-review-oct-19.pdf?la=en.

[28] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

2. FFR volume requirements

The technology mix of current FCAS providers suggests that there is a large FFR capacity already in the NEM. Recognising this existing capacity will likely fulfill a significant portion of the FFR requirement for system intact.

This section examines both the maximum utilisable volume of FFR and the estimated existing FFR capacity withing the current FCAS markets. An illustrative technical specification for FFR is used to estimate the potential volume requirements.

2.1 Illustrative technical specification

To illustrate the effect of introducing an FFR service, an indicative specification has been set. This simple specification is designed to be indicative of the requirements rather than a full specification, as set out for the existing services in AEMO's Market Ancillary Service Specification (MASS).

The illustrative specification is relevant for the mainland NEM. Tasmania has a different frequency containment band and, as a synchronous island, experiences different levels of RoCoF. A variant on the FFR specification would be required for Tasmania, similar to the existing contingency FCAS specifications.

Practical considerations

Consideration should be given to other FFR specifications used in the NEM, such as regional specifications for FFR as an inertia support activity, for opportunities to be consistent.

Response time specification

The response time specification of an FFR service should be set with reference to the time to reach the frequency containment requirement under the expected system inertia and risk size. There is currently no explicit minimum inertia limit in the NEM for system intact, but it is expected that at least 45,350 megawatt seconds (MWs)[29] will be online as a result of the current system strength requirements. Currently the managed risk size (largest single credible contingency in normal conditions) is typically 750 MW but can be as high as 763 MW. Risk size may also increase in the future, as discussed in Section 3.6.

AEMO's *Renewable Integration Study* (RIS) *Stage 1 Appendix B: Frequency control* (RIS Appendix B) showed that nadir times of under 2 seconds could be expected under these conditions[30]. Calculating instantaneous RoCoF, based on inertia and risk size without any assumption on primary frequency response (PFR) or load response, gives an indication of the maximum response speeds that would be needed under different conditions, as shown in Table 3.

Faster response times could be selected to allow for lower RoCoF operation, for example, as a result of changing must run synchronous unit combinations or increases in risk size. However, selecting arbitrarily fast response speeds will limit the volume for FFR that can be delivered from a given capacity of plant. The response speed should be chosen so that the specification does not unnecessarily reduce the FFR volume that could be recognised from the range of FFR capable technologies.

[29] This value is dependent on the system strength requirements and was correct at the time of analysis. See Section B6.5, https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

[30] See Figure 12, https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

A response time equal to or approaching 1 second is expected to be suitable for an FFR specification for the management of credible contingencies under system intact conditions in the mainland NEM.

Table 3 Time to frequency containment requirement

Pre-contingent system inertia (MWs)	Risk size (MW)	Instantaneous RoCoF (Hz/s)	Time to 49.5 Hz (s)
80,000	750	0.24	2.1
60,000	750	0.32	1.5
50,000	750	0.39	1.3
45,300	750	0.43	1.2
45,300	763	0.44	1.1
40,000	763	0.50	1.0

Frequency profile

The frequency profile used to test and value FFR delivery should match the response speed. The current FCAS standard frequency ramp has a 4-second nadir, so is not suited to the valuation of FFR.

Illustrative specification

To illustrate the effect of introducing an FFR service, the following specification has been used.

- Response speed – the value of FFR is the instantaneous MW value achieved at 1.0 seconds from the start of the event (Contingency Event Time[31]).
- Frequency profile – linear ramp from 50 Hz at the start of the event to 49.5 Hz at 1.0 seconds from the start of the event.
- Interaction with R6 – the interaction with R6 requires detailed specification. Here, the FFR response is sustained into the R6 time frame, and it is assumed that any response in the R6 time is valued as R6 FCAS.

Internationally, the way FFR parameters have been defined varies, and may be more complex than the indicative specification presented here. The Nordic FFR requirements specify a different activation time based on three different frequency activation levels[32]. Additionally, a less aggressive initial response closer to 50 Hz may be implemented, such as outlined in National Grid's National Grid's Dynamic Containment service[33].

Should FFR be introduced to the NEM, a detailed specification should be developed including setting a response time, with thorough consideration of current and anticipated power system needs. Development of the specification would require consultation with participants and potential FFR providers.

2.2 Modelled FFR requirements

The effect of introducing FFR has been modelled, using the simplified power system model used to develop the R6-inertia curves displayed in Figure 1. The response of both a battery model (dynamic FFR), and a switched load model (switched FFR) have been measured against the illustrative FFR specification given in

[31] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/primary-freq-resp-norm-op-conditions/market-ancillary-services-specification---v60.pdf?la=en&hash=4E46BE456C8D1DEAF12D0FF922DE4DBA.

[32] See https://www.epressi.com/media/userfiles/107305/1576157646/fast-frequency-reserve-solution-to-the-nordic-inertia-challenge-1.pdf.

[33] See https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/dynamic-containment?technical-requirements.

Section 2.1. Different levels of this FFR response have been introduced into the model to look at the resulting reduction in required R6 volumes.

As a dynamic power system model is used to examine the effect of FFR introduction, rather than a static response based on a market specification, the response from the FFR providers continues into the R6 time frame. It is assumed that this response would be valued as R6. For example, if 164 MW of FFR is scheduled on the battery model, this model also provides 164 MW of R6.

Dynamic FFR Model

To model the dynamic provision of FFR, a battery model was used. The model was set with 1.7% droop and a +/- 150 millihertz (mHz) deadband. The response of the battery was capped at the instantaneous MW value achieved at 1 second FFR response specification, for the injection of the frequency profile described in the illustrative FFR specification.

For dynamic FFR providers, such as batteries with droop type control, the volume of FFR that can be delivered will depend on several parameters, including the inherent speed of the plant's response as well as droop and deadband settings. The droop and deadband setting will set the ultimate MW value that is reached in response to a frequency excursion. Lowering the droop or deadband setting will increase the ultimate MW value that is achieved, and so can affect the volume of FFR that can be recognised, as a proportion of nameplate capacity. Lowering the deadband will also affect the speed of the response, by allowing a provider to respond sooner. In the mainland NEM, under system intact conditions, this can have a noticeable impact, given the relatively tight frequency containment band.

The modelled droop and deadband setting give an ultimate MW output of 47% of maximum power (Pmax) for a 0.5 Hz frequency excursion. To limit the response to the FFR specification, the response was capped at the instantaneous value achieved at 1.0 seconds (~47%). There is some measurement time delay incorporated in the model, that is specific to the model. In practice the proportion of nameplate capacity that can be recognised as FFR will vary between plant, being dependent on the characteristics of individual plant as well as the chosen settings.

Figure 2 shows the modelled response to the reference frequency profile.

Figure 2 Dynamic FFR model

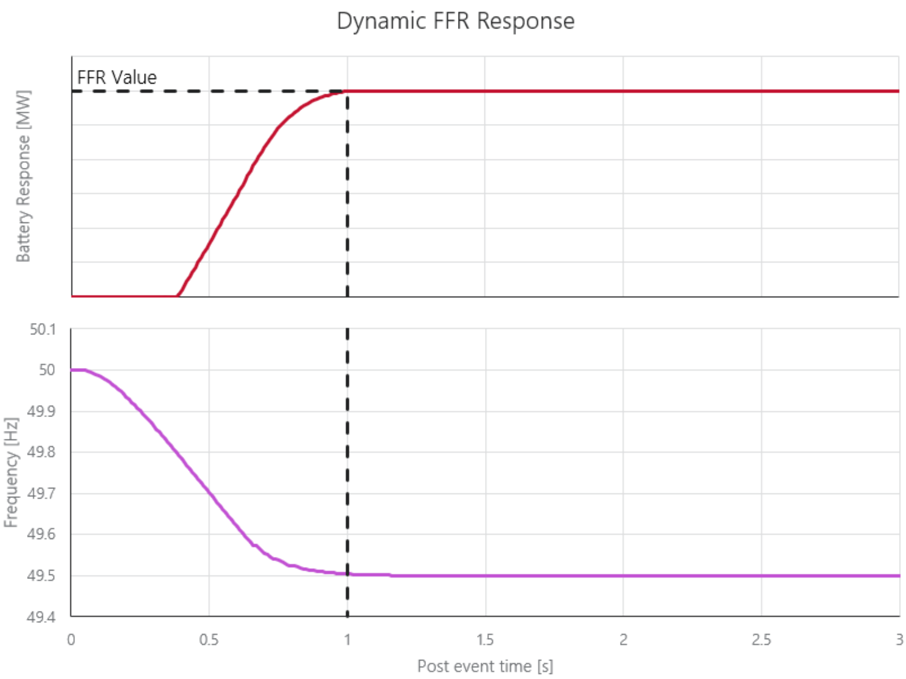
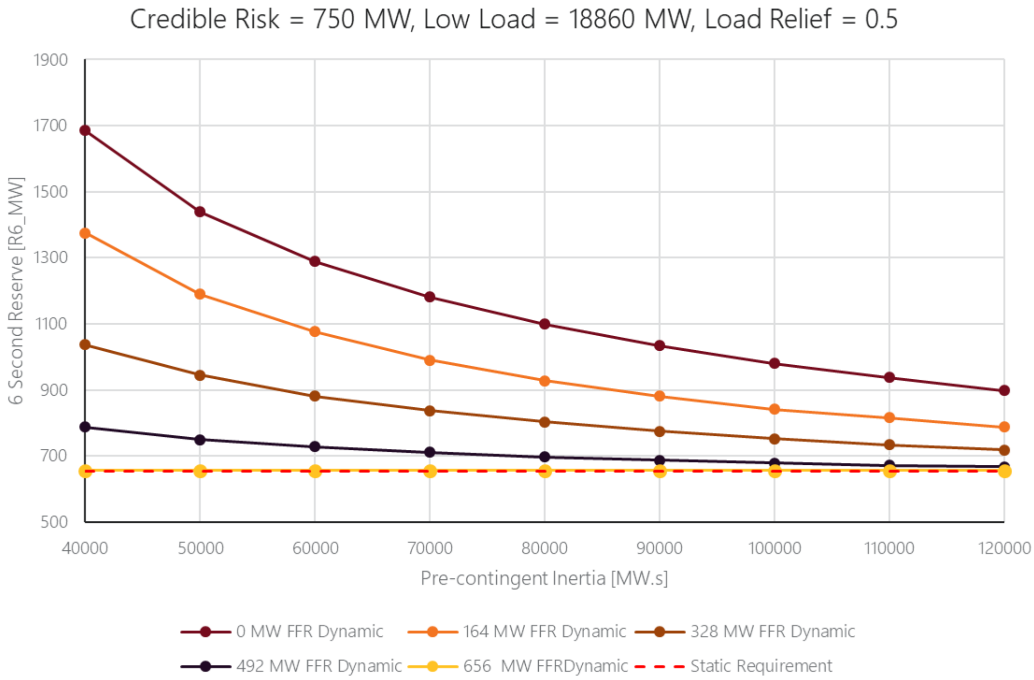


Figure 3 shows the reduction in R6 requirements that can be achieved by introducing progressively greater volumes of dynamic FFR response. At each point on the curves, the combined level of active power required by the critical time (when system frequency reaches the 0.5 Hz containment requirement) is equal to the static requirement (656 MW in this example). This volume is made up by the combined FFR and R6 type response; however, as the R6 response isn't fully delivered within the critical time, a greater volume is required to achieve the required speed. With FFR equal to the static requirement, the R6 requirement is flattened to the static requirement, which is the minimum value.

Figure 3 R6 requirements with increasing levels of Dynamic FFR



Switched FFR model

For switched load type response, the response speed will determine the volume of FFR that can be delivered. The response speed will be limited by the overall speed of the system which includes time to sense the change in frequency, any delays introduced to prevent spurious triggering, and the time taken in communication and disconnect or reduce the load.

In the NEM mainland, under-frequency trip settings for FCAS are allocated at five levels between 49.8 Hz and 49.6 Hz. For simplicity, the modelled switched FFR is allocated evenly across these five trip settings, representing multiple switched providers in aggregate. Switched response may also include a RoCoF trigger, which can be used to achieve a faster response, when a faster response is needed and can help in coordinating different forms of response. For simplicity a RoCoF trigger has not been modelled here.

Figure 4 shows the modelled response to the reference frequency profile.

Figure 4 Switched FFR model

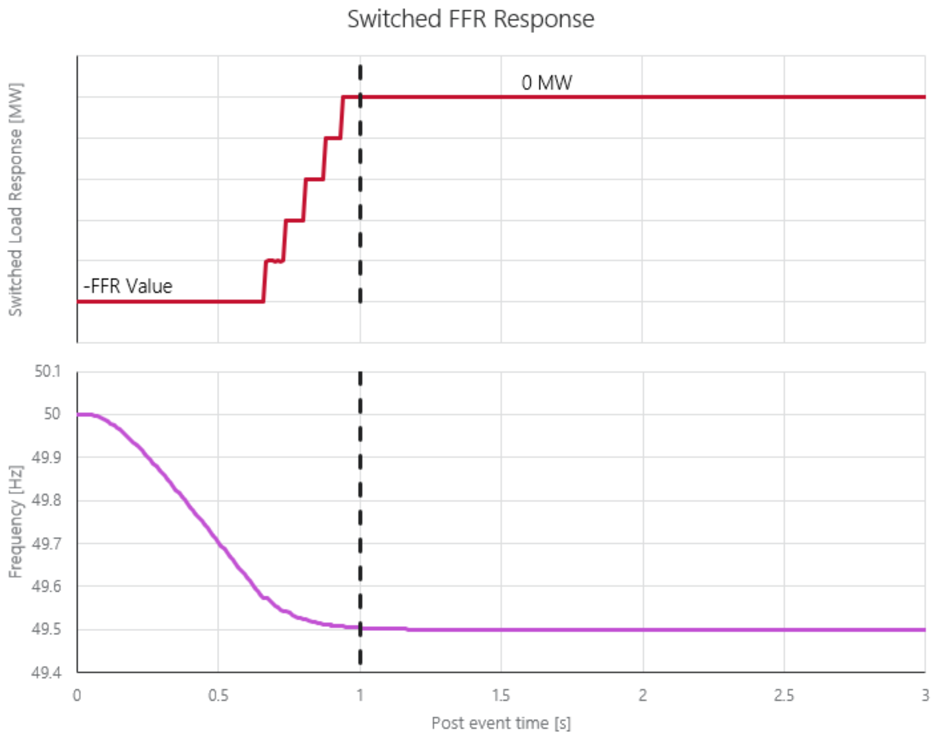
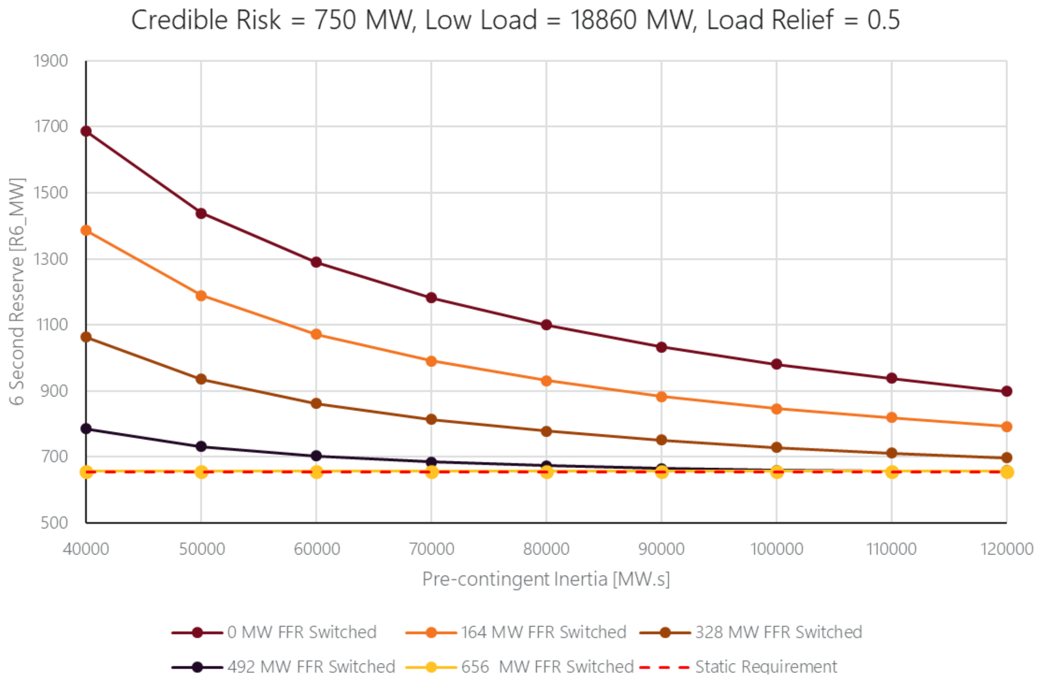


Figure 5 shows the reduction in R6 requirements that can be achieved by introducing progressively greater volumes of switched FFR response.

Figure 5 R6 requirements with increasing levels of switched FFR



2.2.1 Expected range of utilisable FFR volumes

Providing the speed specification for an FFR product is set fast enough to meet the frequency nadir time, the maximum useful volume of FFR, for managing a credible contingency for the system intact conditions, is equal to the static requirement. With the current risk size and load assumptions this is usually in the range of 550 MW for raise and 250 MW for lower. At slower nadir times (higher inertia), less FFR would be needed, although with the existing R6 specification there is some utilisable volume of FFR across the existing inertia range.

2.3 Existing and projected FFR capacity

The existing capacity of FFR type response in the NEM has been estimated based on the capacity of current FCAS provided by technologies that respond within FFR time frames. AEMO expects that a fair proportion of batteries, virtual power plants (VPPs) and switched response currently registered in the R6 and L6 markets should be able to provide some amount of FFR. FFR capability is not exclusive to these technologies; for example, although response from solar is not currently registered in the FCAS market, the response of some solar plant witnessed in events and testing is rapid.

While significant volumes of battery and switched response are already registered for FCAS, not all of these facilities would meet the indicative FFR specification, and individual provider responses have not been assessed to provide this estimate. Also, as faster R6/L6 providers can register for greater volumes than their instantaneous response at 6 seconds (as described in Section 6.9.2), the volumes of registered FCAS will be larger than the true capacity of those providers. However, the existing mix of R6/L6 provision is indictive of a significant capacity of FFR type response capability already being present in the NEM.

As shown in Table 4, there is currently 2,333 R6_MW of registered capacity in the NEM from technologies generally suitable for FFR provision. How much of this capacity would actually be able to register for FFR provision will depend on the FFR specification, and the capability of each provider to meet that specification or change the configuration of their controls in order to meet it.

Table 4 Existing R6/L6 capacity from FFR type providers by technology

Technology Type	Capacity from FFR-type providers (R6_MW)	Capacity from FFR-type providers (L6_MW)
Batteries	170	170
VPPs	13	12
Switched Load	2,150	-
Total	2,333	182

2.3.1 Projected FFR capacity

Information on new battery projects entering the market is collated by AEMO and presented in the NEM generation information publications[34]. Information on battery projects from the November 2020 generation information has been used to provide an indicative view of the potential FFR capacity that could be expected from these projects.

[34] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Based on the unit nameplate capacity an R6_MW value has been estimated, consistent with current guidance on minimum droop settings[35]. Table 5 includes data from the In-Service, Committed, Committed*, Advanced, Maturing and Emerging commitment status categories[36]. In addition to the project development information shown in Table 5, there is a large volume (6,095 MW aggregate nameplate capacity) of projects with a lesser level of demonstrated commitment in the Publicly Announced category.

Table 5 Indicative future battery R6 capacity base on generation information

Project Status	Nameplate capacity (MW)	R6 FCAS capacity (R6_MW)
In-Service	260	170
Committed	20	13†
Total (In-Service, Committed)	280	183†
Committed*, Advanced, and Maturing	27	17†
Emerging	315	198†
Total (All)	622	398†

† Estimated R6 value. These R6 capacities have been estimated using simple assumptions about FFR provision from batteries in general; they are not based on any individual project information, and do not represent the FFR capacity of any individual project.

2.3.2 Summary of FFR capacity information

There is a large volume of R6 capacity from switched response, batteries, and VPPs registered in the market (2333 R6_MW), and much of this capacity is expected to be able to provide FFR.

In addition, information about battery project development indicates there could be an additional 13-219 R6_MW type FCAS capacity also expected to come online from projects with their status between the Committed and Emerging. In addition to these projects, there is a large volume of battery projects with a lower commitment status but have been Publicly Announced. AEMO does not analyse the development pipeline of Switched FCAS in the same way as battery and energy developments, however since the introduction of the Market Ancillary Service Provider (MASP) registration category there has been a significant amount of switched FCAS enter the market from load aggregators. Other technologies, including solar, that do not currently participate in the FCAS markets could conceivably deliver FFR services[37].

Recognising this existing capacity will likely fulfill a significant portion of the modelled FFR requirement for system intact conditions.

[35] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

[36] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. The categories are described under Background Information.

[37] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-working-paper.pdf.

3. Interaction with other services

Introducing an FFR service requires consideration of the interaction with other services, system parameters and processes. This section discusses the interaction with existing FCAS services, PFR, risk size, inertia and the Minimum Inertia Requirements.

Key insights

- **The fastest service is best suited to inertia dependent scheduling** – FFR (raise and lower), as the fastest FCAS services, would be best suited to scheduling with dynamic volumes that account for system inertia and the dynamic effect of load relief. If FFR is introduced, slower FCAS services, including R6/L6, can be scheduled with static volumes, accounting for the static effect of load relief. Scheduling static FFR volumes may be appropriate as interim measures for procurement of FFR.
- **Inertia and FFR should not be combined within the same service for management of system intact conditions** – inertia and FFR both provide a valuable response, however, they are fundamentally different and should not be combined within the same service.
- **Extending contingency FCAS co-optimisation with Risk Size to system intact operation should be further investigated** – with inertia dependent FCAS volumes under system intact operation, FCAS-Risk Size co-optimisation may allow for greater efficiencies across all contingency FCAS services. Introduction of this co-optimisation is non-trivial and would require development of more complex constraints that have limitations in their ability to accurately reflect multiple non-linear relationships between constraint terms.
- **5-minute co-optimisation between FFR and inertia is not a high priority component of FFR service development** – FFR-inertia co-optimisation would introduce significant complexity into service scheduling, while the efficiencies it would introduce may not be as large as other potential changes in the FCAS markets. Development of an inertia service should consider the requirements to maintain inertia for broader reasons than frequency containment for credible events, protected events, and islanded operation of regions.
- **5-minute co-optimisation between FFR and other FCAS services is not a priority component of FFR service development** – development of service specifications that minimise the overlap between FFR and the other FCAS services would reduce or eliminate the need to develop 5-minute co-optimisation between contingency FCAS services.
- **Narrow band PFR response and FFR are compatible** – FFR and narrow band PFR can both operate together. FFR providers can apply piecewise linear droop response to be less reactive to smaller frequency changes.
- **Broad-based PFR does not discourage FFR provision:** – broad-based PFR provision lessens the integration challenges associated with FFR delivery and would be expected to lower the number of switched FFR activations. It may also encourage some FFR providers to respond sooner, allowing them to provide more FFR.
- **The coordination of FCAS FFR with Inertia Service Providers should be further considered** – the introduction of an FFR as part of a contingency FCAS service would need to be coordinated with the existing measures for securing islanded regions. This could be achieved by not using FCAS-based FFR

for the management of islanded regions, or by taking the FFR available through FCAS markets into account when setting minimum and secure inertia levels, and scheduling FFR via FCAS for the management of islanded regions.

3.1 FFR scheduling

Assuming FFR is introduced as a new service, there are options on how the volume of FFR is scheduled. Static volumes may be appropriate as interim measures for procurement of FFR. Having inertia dependent volumes of FFR, rather than R6/L6, may be more appropriate for longer-term arrangements.

3.1.1 Static volume of FFR

The simplest way of scheduling FFR would be to set a static volume for raise and lower. The inertia dependent R6/L6 constraint curves would be adjusted downwards to account for the procurement of a fixed amount of FFR. R6/L6 would be set according to system inertia, with less R6/L6 procured at low inertia than would occur without recognising FFR.

The disadvantage of this approach is that either a low volume would need to be set, or the volume of FFR would be underutilised at higher inertia values.

This approach may be suitable in introducing FFR with simplified procurement arrangements, as described in Section 5. It would allow the introduction with FFR with minimal changes to the MASS specification of existing services.

3.1.2 Inertia dependent volume of FFR

Rather than procuring a static volume of FFR, the volume of FFR could be made dependent on system inertia, with more FFR scheduled at lower inertia. Under this arrangement, R6/L6 would be set as static volumes, as they are under the existing arrangement for system intact.

The greater volumes of R6 required to arrest frequency under low inertia are needed to ensure the active power response is fast enough, rather than there being a requirement for a greater magnitude of response. Making FFR the inertia dependent service within the suite of FCAS services is consistent with procuring the speed of response needed, rather than procuring a magnitude of response to indirectly achieve the required speed. Inertia dependent FFR volumes are employed by ERCOT[38].

3.2 Interaction with R6/L6

Assuming FFR is introduced as a new service, the interface between R6/L6 and FFR requires definition. Minimising overlap between R6/L6 and new FFR services may require amendment of the MASS for the existing products. The measurement of R6/L6 starts at the Contingency Event Time, so delineation between and FFR services and the existing R6/L6 services may not be clear.

The way R6/L6 FCAS are currently measured means that registered FCAS values for faster providers can be less than the instantaneous MW change by 6 seconds[39]. This valuation method rewards faster provision but would also complicate the delineation between FFR and the R6/L6 services. There is potential to revise the existing R6/L6 specification to more clearly differentiate FFR as a low inertia product, by reducing dynamic R6/L6 requirements at high inertia.

[38] See https://www.nerc.com/comm/PC/IRPTF_Webinars_DL/2020-04_Webinar-FFR_White_Paper.pdf.

[39] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

Any future changes to the existing R6/L6 specification would alter the R6-inertia curves (displayed in this report) as they are based on the current MASS, however the general effect of introducing FFR is the same. Future changes may include those currently being considered by AEMO's General MASS Review[40].

3.2.1 FFR-R6/L6 co-optimisation

The possibility of R6/L6-FFR co-optimisation has been raised as a potential attribute of an FFR service in order to increase efficiency[41]. The existing time-based segmentation of FCAS products (6-second, 60-second and 5-minute) has been specified to maintain the MW response required to keep frequency within the Frequency Operating Standard (FOS) containment criteria over the full market dispatch interval, until redispatch and regulation FCAS can address the active power imbalance. There is no co-optimisation between the contingency services as they are designed to provide this continuous response, with as little overlap as is practical between the services. In many cases, the time-based segmentation simply separates how continuous responses from FCAS providers are valued across different time intervals.

Assuming an FFR product is specified in keeping with this design, by extending the existing suite of services to include valuation of response faster than the existing R6/L6 services, there may not be a clear benefit in including FFR-R6/L6 co-optimisation. The portion of a provider's response that is faster than R6/L6, and meets the FFR specification, would be valued under the FFR service and scheduling more FFR would be the most direct way to increase the speed of the FCAS response. Should it eventuate that acquiring larger volumes of R6/L6 is more economic than acquiring the corresponding amount of FFR, this may suggest a need to revisit the service specifications, rather than to introduce co-optimisation.

The practical implementation of this potential co-optimisation should also be considered. Constraint design to introduce a 5-minute co-optimisation between services would also be more involved than current arrangements. It also needs to include interaction with inertia, and potentially risk size in the future. Currently, there is a form of co-optimisation for R5 and regulation FCAS, using a fixed ratio (1 to 1), but the interaction with the existing R6 specification and an FFR would be more complex.

3.3 Interaction with PFR requirements

The Mandatory Primary Frequency Response Rule came into effect in March 2020[42], and AEMO is currently facilitating the roll out of mandatory PFR[43] in conjunction with generators. The rule includes a June 2023 sunset on the mandatory provision of PFR. The arrangements for ongoing PFR after the sunset period are being considered by the AEMC as part of the *Primary frequency response incentive arrangements* rule change process, including the deadband specification of any enduring technical obligation, as well as incentives for future PFR provision[44].

The future PFR arrangements may affect FFR providers in two ways; they may place an obligation on FFR providers to respond to frequency at some deadband, and they may also influence the quality of frequency control under normal conditions.

Narrowband PFR obligations

The Interim Power Frequency Response Requirements (IPFRR) allow for a variable droop setting to be applied[45]. Dynamic FFR providers wanting to apply a lower (more reactive) droop setting to maximise FFR delivery would have no obligation to use the same aggressive droop at a narrow frequency band. These

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[40] See https://aemo.com.au/en/consultations/current-and-closed-consultations/mass-consultation.

[41] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

[42] See https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

[43] See https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response.

[44] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

[45] See Section 3.3 of the IPFRR, https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en.

providers would be able to apply the maximum (least aggressive) droop setting of 5% close to 50 Hz, reducing their level of response to ongoing frequency movement. Variable droop is part of the specification for National Grid's Dynamic Containment service, which is an FFR type service that has a +/-15 mHz deadband[46]. The IPFRR obligations do not apply to providers of switched FCAS from load providers.

Quality of frequency control under normal conditions

Regardless of how it is maintained, the quality of frequency control during normal conditions may impact the quantity of FFR certain providers can supply. If frequency is tightly controlled, Dynamic FFR providers may be able to set tighter deadband settings, or start a more aggressive response sooner, as this would be less onerous with tighter control of frequency. As described in Section 2.2, this may allow some providers to supply greater volumes of FFR. The level of PFR may also reduce the number of excursions outside the normal operating frequency band (NOFB), reducing the cost of supplying switched FFR.

3.4 Interaction with inertia

3.4.1 Valuation of inertia as FFR

The possibility of valuing inertia and FFR under the same service has been raised in the AEMC's direction paper on the FFR rule[47]. FFR and inertia can both reduce RoCoF, however, FFR is not a direct substitute for synchronous inertia, and is physically different[48,49]. Specifically:

- Inertia from synchronous units provides an inherent response to slow RoCoF, but will not arrest system frequency.
- Some types of FFR can inject a sustained active power response to correct an active power imbalance, and so can arrest a change in system frequency.

Distinguishing between different forms of fast active power response is also important.

The type of FFR most relevant to the problem definition (Section 1.3.3) and suitable to be valued by the illustrative service specification (Section 2.1) provides a sustained active power injection, that is either related to system frequency by a droop coefficient (dynamic FFR), or is a static injection of active power triggered by frequency (switched FFR). This type of FFR is like contingency FCAS, just delivered faster than the current R6/L6 specification.

There are other forms of fast active power injection, that may be referred to as FFR, but provide different forms of response. Synthetic inertia provided by wind farms and virtual inertia provided by batteries are examples of responses related to RoCoF, and are closer to the response of synchronous inertia.

A list of technologies able to provide sustained FFR is provided in AEMO's *Fast Frequency Response in the NEM Working Paper*[50]. An overview of the capability and operations of a range of technologies that can provide fast active power responses is in GE Energy Consulting's *Technology Capabilities for Fast Frequency Response*[51], commissioned by AEMO. NERC also provides a comprehensive review of different forms of frequency response in its *Fast Frequency Response Concepts and Bulk Power System Reliability Needs*[52] white paper.

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[46] See https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/dynamic-containment?technical-requirements.

[47] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

[48] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-coversheet-20170310.pdf?la=en.

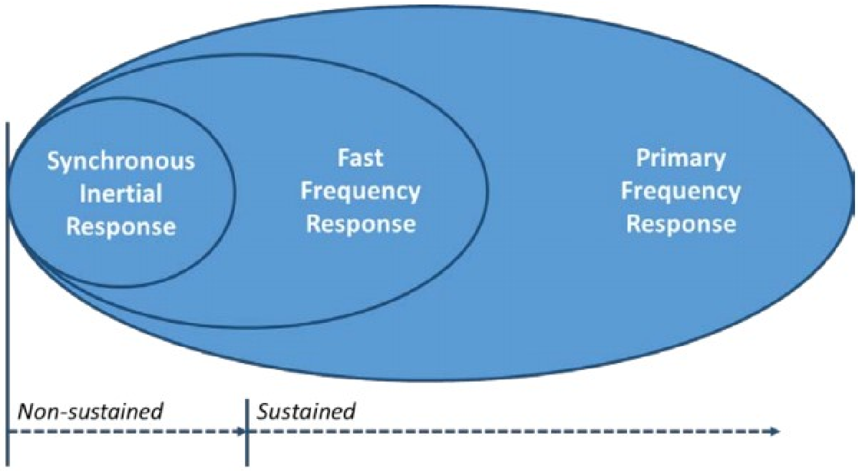
[49] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-working-paper.pdf.

[50] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-working-paper.pdf.

[51] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/20170310-ge-ffr-advisory-report.pdf?la=en.

[52] See https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

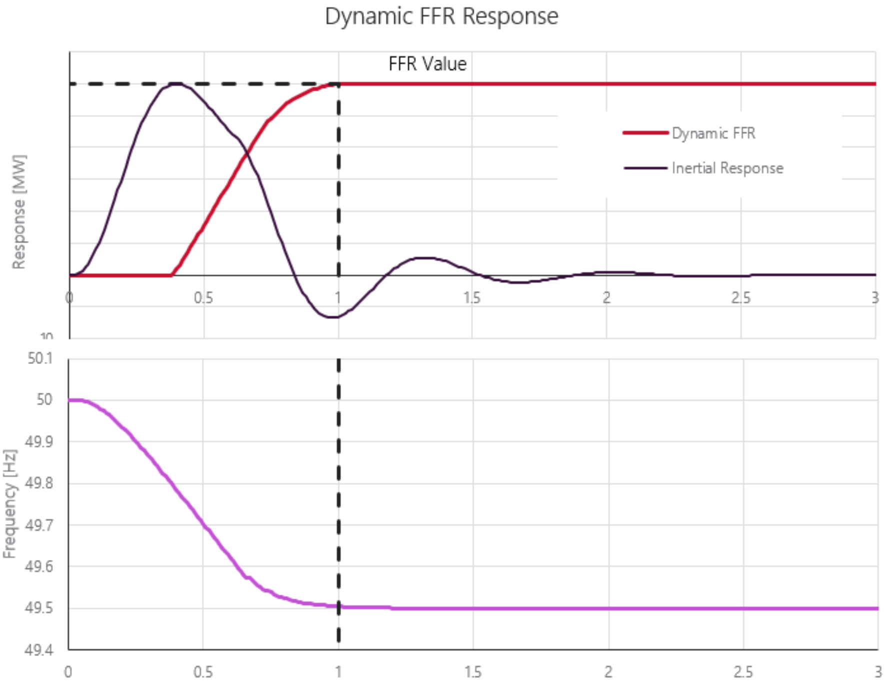
Figure 6 Simultaneous contributions of inertia response, PFR and FFR



Source: NERC, at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

While it is useful to distinguish between inertia and contingency FCAS type FFR, it does not mean that synchronous inertia, and inertia like responses are not valuable, only that they fulfill different roles in maintaining system security[53]. Figure 7 shows both a synchronous inertial response and a dynamic FFR. The inertial response is not sustained, and in this example will be attributed no value if measured against the illustrative FFR specification provided in Section 2.1. A specification for contingency FCAS type FFR is not suitable to the valuation of inertia. The incentivisation of very rapid active power injection (sub 1 second), or control based on (or related to) RoCoF, would require consideration of a different set of system stability and security issues.

Figure 7 Inertial response example



[53] Development of inertia markets is further discussed in Section 3.4.

Operational considerations

Inertia and FCAS are treated separately in FCAS constraints that manage the scheduling of the volume of contingency FCAS. It is expected the use of inertia dependent FCAS constraints will be extended to manage frequency containment under system intact conditions. Combining FFR and inertial response into a single service would complicate the scheduling of the correct volumes of services.

While it may be possible to derive equivalences between inertia and FCAS type responses in some instances, the responses have fundamentally different dynamics, and relationships between them may only be accurate over specific ranges. To ensure system security, AEMO would need visibility of the volumes of inertia response separate to the volumes of FCAS type response (across different time frames) that are being scheduled. The use of Dynamic Security Assessment tools, and possible extensions to use of these tools in the future, would also require visibility of inertia separate to FCAS type responses.

There are potential benefits for maintaining a base level of inertia, outside of managing system frequency containment within a given market interval, as described below in Section 3.4.2.

3.4.2 NEM-wide inertia safety net

The 2017 *Managing the rate of change of power system frequency Rule*[54] introduced a requirement for a threshold level of inertia to be provided when there is a credible or protected risk of islanding part of the system, and sufficient inertia to maintain power system security during islanded conditions. Under the current National Electricity Rules (NER), no specified level of inertia is required under normal operating conditions, or to ensure a resilient system response to non-credible events.

Additionally, the NER specify that any inertia sub-networks need to be entirely within a NEM region boundary. This means there are no provisions to determine minimum inertia requirements for operating two or more regions islanded together. For regions such as Victoria and New South Wales, the number of inter-regional interconnections means the risk of single-region islanding is deemed to be remote. Victoria and New South Wales have islanded together historically, following the separation of Queensland and South Australia. As synchronous generation decommits into the future, the amount of inertia seen across the whole NEM will also continue to decrease, potentially impacting the operability of frequency islands.

AEMO's RIS Stage 1 Report[55] initially recommended investigation of a NEM-wide inertia safety net for system intact conditions, which was explored in detail in the RIS Appendix B. AEMO provided initial projections of when this safety net may be required in Appendix 7 of the 2020 Integrated System Plan, and will be undertaking a more detailed assessment of the safety net concept. This work is currently scheduled as part of AEMO's Frequency Control Workplan[56].

The following potential benefits of system inertia safety were highlighted by the RIS. These benefits should be viewed with the forecast speed of system inertia reduction[57], and the uncertainty around the rate of the reduction.

Progressive expansion on the system's operational envelope

A system inertia safety net that can be revised over time would allow the envelope of operating experience to be progressively expanded and increase the opportunity to learn from operational experience. Replacing synchronous inertia with fast acting control will result in a system with very different system dynamics, with border considerations the frequency containment.

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

[55] See https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

[56] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

[57] See https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--7.pdf?la=en.

GE Energy Consulting's 2017 report *Technology Capabilities for Fast Frequency Response*[58], commissioned by AEMO, recommended that AEMO consider maintaining a minimum level of inertia, as this would have other benefits beyond frequency control. All areas of system stability, including transient and small signal stability, as well as frequency stability and RoCoF, need to be managed through the transition to low inertia.

Planning the system

A system inertia safety net that can be revised over time would give some level of certainty to the timing of system inertia reductions to allow for appropriate system planning. This would help a greater understanding of the effect of higher RoCoF on distributed photovoltaics (PV), utility-scale generation, switched reserve providers, and protection relays used in various network functions (including emergency frequency control schemes [EFCS]), and ensure that appropriate measures are in place to maintain system security.

3.4.3 FFR-Inertia co-optimisation

Currently there is no inertia service that contributes to the management of system intact conditions, however, the ESB's Essential System Services Post 2025 Market Design initiative is investigating the development of inertia services[59]. The possibility of inertia-FFR co-optimisation has been raised as a potential attribute of an FFR service in order to increase efficiency[60]. If the FFR is scheduled as an inertia-dependent volume, as described in Section 3.1.2, it is conceivable that inertia-FFR co-optimisation could be introduced so that the FFR and prospective inertia service can compete on price.

Range of possible co-optimisation

The upper limit to the possible range of inertia-FFR co-optimisation is the value at which dispatching more inertia or FFR does not reduce total FCAS quantities. FCAS always needs to replace the active power lost during a contingency to arrest frequency, so R6 FCAS volumes cannot be reduced below the static requirement. Increasing inertia can reduce the FFR requirement.

The lower limit to the possible range of inertia-FFR co-optimisation is the minimum level of inertia or FFR that that must be online. Currently the units that must be online to support system strength provide a default minimum of around 45,300 MWs[61]. An indicative initial inertia safety net value of between 55,0000 MWs and 65,000 MWs has been proposed[62], however this is an illustrative value only. Should an inertia safety net be implemented, the initial value would be set according to the conditions at the time of implementation. The minimum value of FFR will depend on the details of the service specification and scheduling arrangements.

Potential impact of co-optimisation

The base option to manage low inertia conditions is the introduction of inertia dependent R6. The ability to reduce R6 volumes can act as a yardstick to measure the relative impact of inertia relative to FFR. This is shown in Figure 8. Looking at the steepest part of the curve (below the proposed initial safety net values), where the impact of inertia is greatest, the introduction of 164 MW of FFR results in the same R6 reduction as introducing ~14,500 MWs of inertia (equivalent to ~6 to 9 large thermal units). Introducing 328 MW of FFR results in the same R6 reduction as introducing ~50,000 MWs of inertia (equivalent to ~20 to 30 large thermal units). Introducing 656 MW of FFR reduces R6 to the minimum volume across the whole range of the inertia modelled.

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[58] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf.

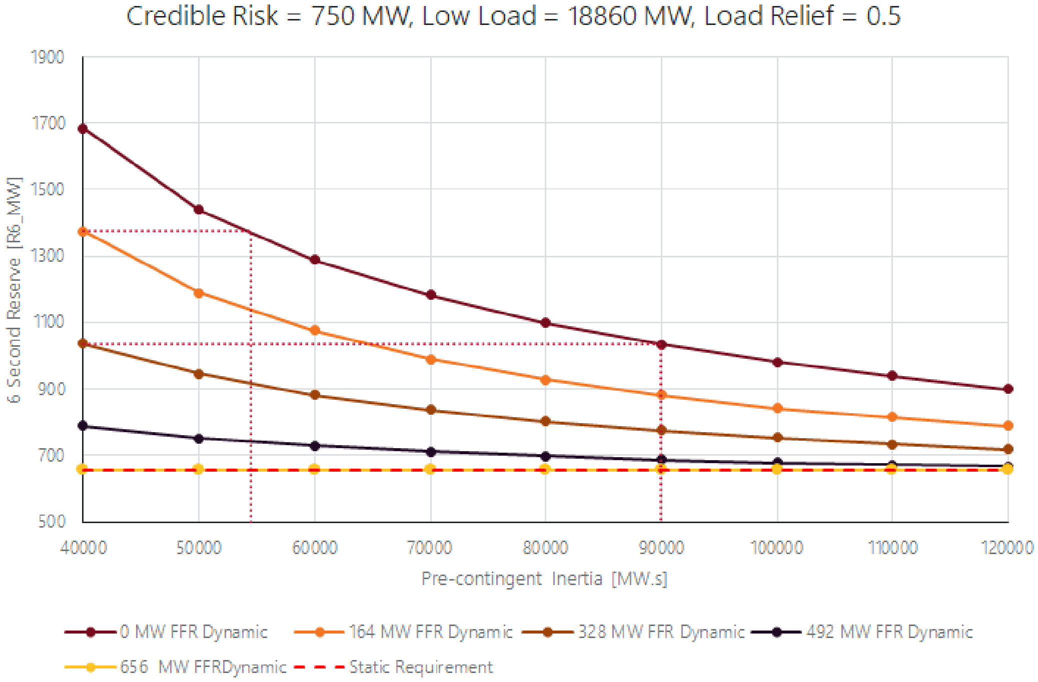
[59] See http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/P2025%20Market%20Design%20Consultation%20paper.Final_.pdf.

[60] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

[61] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

[62] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

Figure 8 Relative impact of inertia and FFR



Discussion

Scheduling a relatively small amount of FFR can offset a large amount of inertia for managing frequency containment. Scheduling the static requirement of FFR, assuming this is specified with a response time as fast as the minimum nadir time, will allow operation across the projected range of inertia.

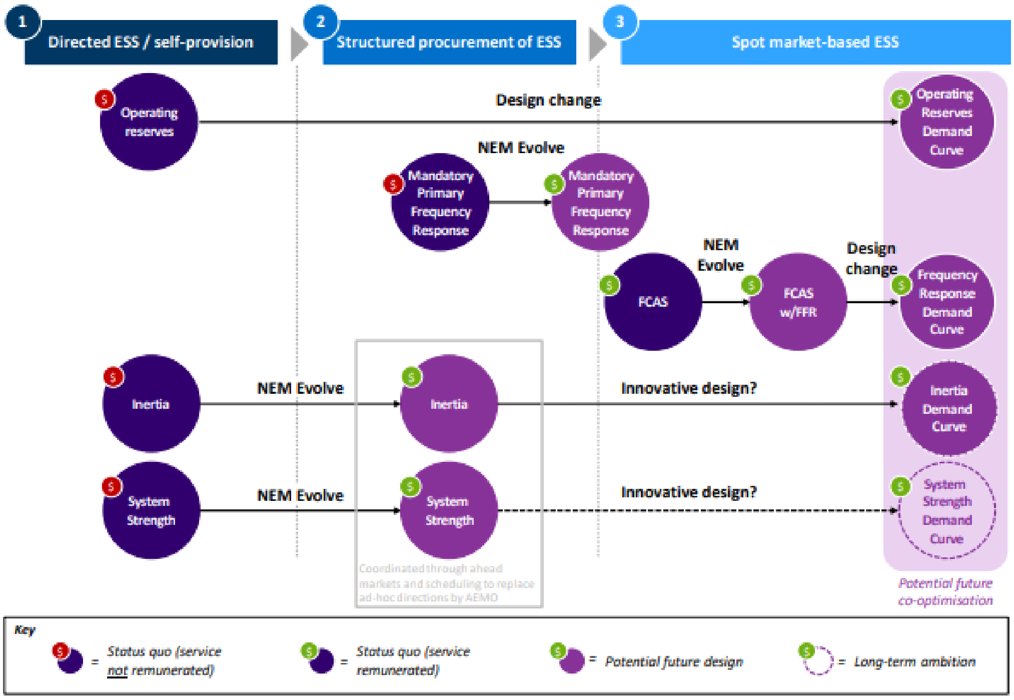
This suggests that inertia-FFR co-optimisation may not bring material efficiencies, under all conditions, so its potential introduction should be considered carefully. While this co-optimisation may be theoretically possible (although the implementation detail would need to be worked through in the NEM context), it would likely add significant complexity to the scheduling of services. This would mean large-scale changes to existing systems, as well as potentially less flexibility to update these systems in the future. It may also make the implementation of other measures to introduce new efficiencies more difficult, such as co-optimisation with risk size.

As discussed in Section 3.4.2, there are several reasons for holding a minimum value of inertia in addition to managing frequency containment, including the ability to progressively manage the trade-off between inertia and FFR. The design of inertia services should consider these aspects of inertia provision. Bringing on synchronous units to provide inertia would also have some impact on the energy market, as most thermal units have a minimum active power that they need to operate above. Synchronous condensers and some generating units, including hydro units, can supply inertia at zero load.

There are larger considerations around the operational and security management implications of real-time inertia markets that are beyond the scope of this report. The ESB's *Essential System Services Post 2025 Market Design initiative*[63] has outlined a potential development pathway for inertia markets, starting with structured procurement with the potential to development into spot market arrangements, as shown in Figure 9.

[63] See https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf.

Figure 9 Overview of procurement and scheduling options for Essential System Services



Source: FTI analysis

3.5 Interaction with Minimum Inertia Requirements

FCAS is used in the management of system intact conditions, and in the management of islanded regions. As outlined in Section 1.3.1, the Minimum Inertia Requirements set the required regional minimum inertia values to operate in an island condition (Secure operating level of inertia), or when there is a credible risk of islanding (Minimum threshold level of inertia). Under the inertia rules, FFR can be used (as an inertia support activity) to reduce the required levels of inertia. The 2020 *Notice of South Australia Inertia Requirements and Shortfall*[64] identified the need for FFR (in addition to existing FFR capacity) to assist in supporting the security of South Australia when islanded.

The introduction of FFR as a contingency FCAS service would need to be coordinated with the existing measures for securing islanded regions. The FFR specification between Inertia Service Providers and FCAS FFR providers could conceivably be different, as island regions are subject to different system conditions (inertia, load relief and risk size) as well as different frequency containment requirements. This coordination could be achieved by either:

- Not scheduling FFR via FCAS for islanded regions, and using the arrangements in place with Inertia Service Providers, or
- Taking the FFR available through FCAS markets into account when setting Minimum and Secure inertia levels, and scheduling FFR via FCAS for the management of islanded regions.

Under the existing Inertia Requirements Methodology[65], the availability of fast FCAS (R6/L6) in each inertia sub-network is used in determining the inertia requirements. A secure operating level of inertia is defined as an operating condition where the amount of inertia in an inertia sub-network is consistent with both the availability of fast FCAS and the fast FCAS required to maintain an acceptable frequency.

[64] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F.

[65] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

The introduction of an FFR FCAS service would encourage FFR availability, and the Inertia Requirements Methodology could be updated to include consideration of the FFR available through the FCAS markets. FFR FCAS could then be scheduled and renumerated though the FCAS markets for both intact conditions and under islanded conditions. Under these arrangements there would be less need for Inertia Service Providers to contract with FFR to ensure availability.

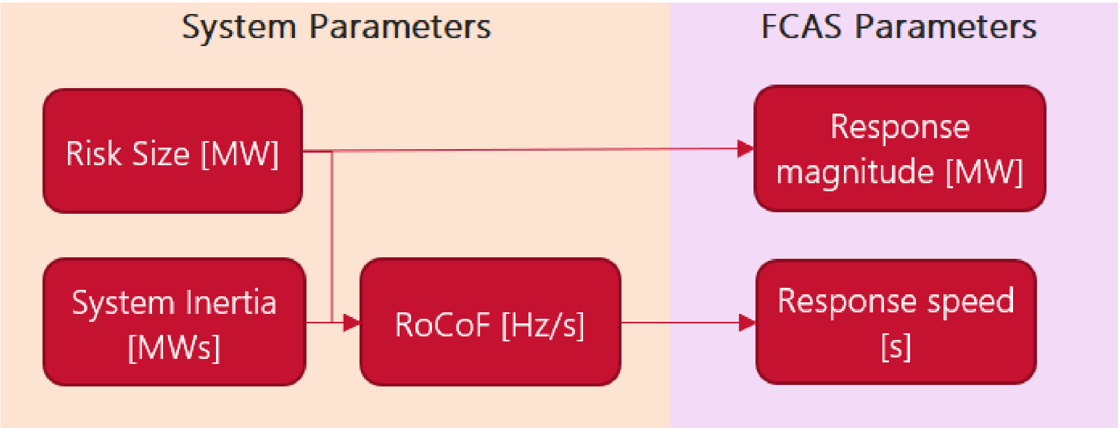
Using FFR FCAS to manage both separated regions as well as system intact complicates the service specification. Different specifications may be appropriate in islanded regions due to the different frequency containment criteria and system conditions. This complication would not be unique to FFR, as it is relevant to the existing FCAS services. The indictive FFR specification used in this report is relevant for system intact.

This development would impact on the obligations on transmission network service providers (TNSPs) as Inertia Service Providers and requires further discussion and consultation.

3.6 Interaction with risk size

The size of the managed contingency (risk size) affects the magnitude of the required FCAS response, as the active power that is lost from the system needs to be replaced in full (by a combination of FCAS and load response) for the system frequency to be arrested. Like inertia, risk size also affects RoCoF and so influences the speed of the required response, with larger risk size resulting in higher instantaneous RoCoF. The relationship between risk size and required FCAS parameters is shown in Figure 10. Load relief also affects the dynamic and static FCAS requirements but has been excluded from the diagram for simplicity.

Figure 10 Relationship between risk size and required FCAS parameters



In the NEM there is no design limit to risk size. Recently, the risk size has typically been around 750 MW, set by Kogan Creek, but can be as high as 763 MW depending on Kogan Creek's output. The next largest unit in the NEM is Eraring at 720 MW.

Any substantial increase to the size of the largest credible risk, either through upgrades to existing plant, connection of new large generators, or the coupling of the risk of trip of smaller generators through intertrip schemes associated with common transmission infrastructure, would change the requirements for frequency management and ancillary services.

Secondary risks are disturbances to the power balance that may happen alongside the loss of the largest generator (primary risk). The disconnection and reduction of distributed solar PV is already being included in the frequency management of islanded regions of the NEM[66]. Explicit management of this secondary risk may by required under system intact conditions in the future. AEMO is taking action to reduce the impact of this

[66] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F.

secondary risk[67]. Reclassification of non-credible contingencies in abnormal conditions can also increase the LCR.

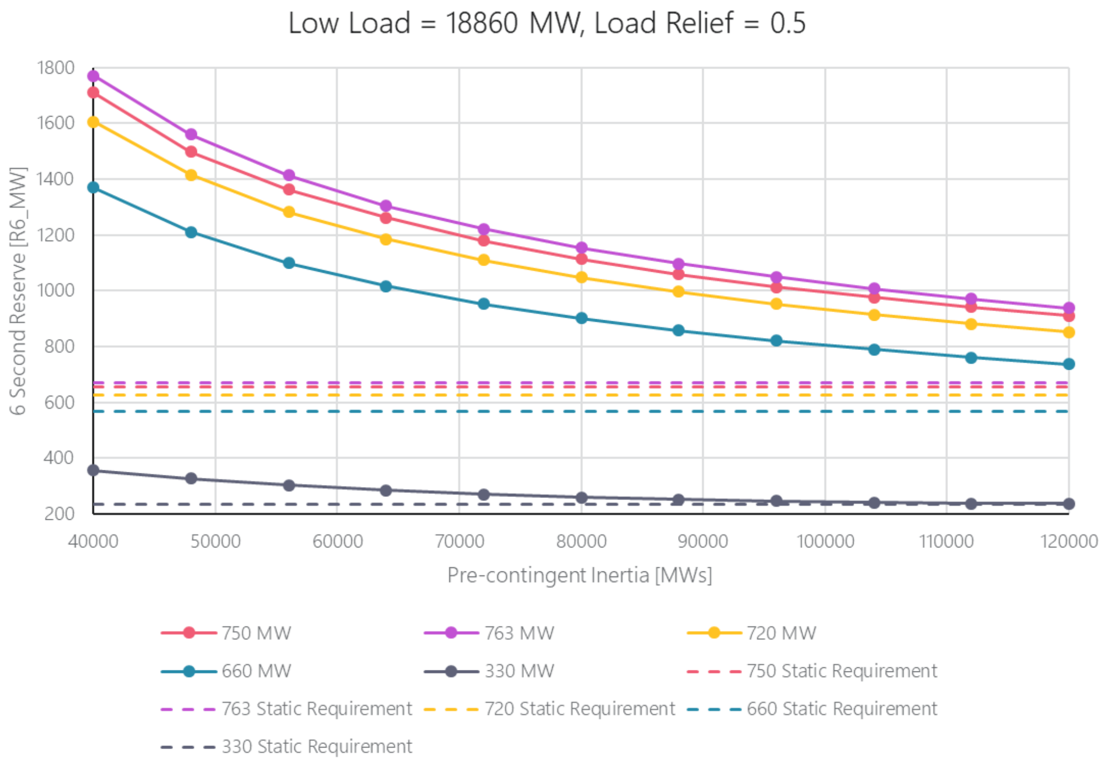
3.6.1 Risk-FCAS co-optimisation

Currently, the risk size is co-optimised with FCAS in the scheduling of FCAS when managing an islanded region. Under these conditions the FCAS requirements are higher and are inertia dependent, so the reduction in risk size can have a significant impact.

For NEM intact conditions, FCAS is co-optimised with energy, but not with risk size. Currently FCAS is not inertia dependent, as historically there have been higher levels of inertia, as so risk size reduction would have less of an impact. With the introduction of inertia dependent FCAS volumes for system intact, the effect of risk size reduction would be greater. As risk size changes the magnitude of the required frequency response, it affects the static requirement as well as the required speed of response. This means reducing risk size can reduce required FCAS volumes across all service speeds.

Figure 11 shows an example of modelled R6 requirements under different sized risks. Reducing the risk size by 43 MW (763 MW to 720 MW) under low inertia could reduce R6 requirements by ~150 MW. At high inertia this reduction would be less, although still significant. The static requirement would also be reduced by 43 MW, reducing the requirement of the slower services. This example is from the baseline option, without FFR. In a scenario where FFR and R6 are being scheduled in tandem, as reducing the risk size reduces RoCoF the total FCAS requirement of the faster services would reduce.

Figure 11 Example R6 requirements for different risk sizes



Although risk size is currently co-optimised with FCAS in the management of islanded regions, the implementation of similar arrangements for systemin intact is non-trivial. The way constraint equations are implemented, with linear Left Hand Side (LHS) terms, may affect the efficiencies that can be practically realised. For Tasmania and South Australia islanded, the risk size and FCAS are co-optimised around a single

[67] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en.

assumed inertia value. For the NEM intact, the range of operation conditions is larger and the relationship between FCAS requirements, including any FFR service, and risk size is non-linear.

3.7 Summary of co-optimisation options

In considering potential 5-minute co-optimisation between services, the co-optimisations that offer the highest efficiencies should be considered first, as adding additional co-optimisations adds increasing levels of complexity and can impact overall efficiency.

Contingency FCAS is already co-optimised with energy. Introduction of FFR could achieve large efficiencies independently of any potential co-optimisations. Extending contingency FCAS co-optimisation with Risk Size to system intact operation has the potential to introduce substantial efficiencies but has its own implementation challenges. Consideration of further layers of 5-minute co-optimisation may not achieve substantial efficiencies but could impact on the ability to accurately parameterise higher priority co-optimisations.

4. Technical requirements for FFR provision

Key insights

- **FFR market design should assume regional FFR requirements** – it should be assumed that regional requirements will be placed on FFR provision, either through regional maximums or regional minimums or a combination of both.
- **FFR market design should assume there will be a minimum number of FFR providers**– FFR should be delivered from multiple providers at any one time.
- **FFR market design should consider a maximum cap on FFR provision from individual providers**– limiting the maximum delivery of individual providers will minimise integration issues, promote geographic diversity, and help prevent the incentivisation of FFR development that may not be able to be able to be fully integrated. FCAS participants that aggregate geographically separated responses may not need to be subject to the same limitations.
- **FFR service registration may include additional technical studies** – FFR registration may include additional technical studies that current FCAS services may not necessarily require. The need for these market registrants to undertake these studies for each project is expected to be reduced by applying volume caps on individual providers and having regional requirements.
- **FFR market design should assume a minimum requirement for dynamic FFR** – dynamic and switched FCAS have different properties, and a minimum dynamic response is needed across the FCAS services.

4.1.1 Geographic diversity and locational limits

Fast Active Power Response (FAPR) refers to a fast (sub-second) active power response from resources including batteries, other inverter-based resources (IBR) and some types of load response. FAPR can be triggered on a range of system quantities to manage a variety of security issues. FFR can be thought of as a form of FAPR, triggered on frequency and designed to assist with frequency stability.

Integration of FAPR brings its own challenges. International studies into the design of wide area monitoring and control systems utilising FAPR have found that if delivered in the wrong location it can affect angular separation between regions, increasing the risk of regional separation[68,69]. It is conceivable that similar challenges could arise in the NEM, if large locational concentrations of FFR were to develop. Locational distribution of FFR, as well as broad-based PFR more generally, would reduce integration issued posed by locational FFR concentrations, as well as provide a more resilient response to non-credible events.

There are other considerations for high locational concentrations of FFR including local voltage management, coordination with UFLS/over-frequency generation shedding (OFGS), and interaction with Special Protection Schemes (SPSs). Co-ordination of FFR with UFLS is already presenting challenges in South Australia[70].

[68] See https://www.nationalgrideso.com/document/144441/download.

[69] Icelandic Operational Experience of Synchrophasor-based Fast Frequency Response and Islanding Defence, CIGRE C2-123 2018.

[70] Refer to Section 6.2 of PSFRR - Stage 2 Final Report, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-2/2020-psfrr-stage-2-final-report.pdf?la=en.

Changes to SPSs have been needed to better co-ordinate them with FFR after issues have become evident through system events[71].

High regional concentrations could also affect post contingent event energy dispatch. Interconnector limits do not consider FCAS dispatch. However, if the post contingency frequency response is relatively large on one side of the interconnector, and this response places the interconnector flow above its limits, the NEM Dispatch Engine (NEMDE) will respond by constraining energy dispatch on the responsive side. Regional diversity of frequency response, including the response from FFR providers, minimises the change in interconnector flows following contingent events.

Transparency of integration issues

Should an FFR market incentivise FFR development, potential providers may have little visibility of these issues. There may be locational limits to FFR delivery that are not immediately evident, and integration issues that require detailed technical analysis to resolve. AEMO and TNSPs need to be able study the impact of FFR, before the FFR is operating as part of the market.

Some of these issues could be resolved by changing the way ancillary services are registered. Historically there would be little that limits FCAS delivery, so project developers could have some level of certainty about being able to register a certain capacity of FCAS. As the integration issues related to FFR are potentially greater, processes of a similar nature to (or even connected with) the approval of plant performance standards could be applied to assess integration issues before FCAS market registration. This would give greater certainty to potential providers, and allow AEMO and TNSPs to assess and identify issues in advance. Some of the studies that would be needed, for example co-ordination of FFR response with EFCS, are not able to be undertaken readily by project developers at this time.

Service reliability

The reliability of FFR provision would be increased if spread across more providers. There have been several occurrences historically of incorrect local plant configurations resulting in failure to deliver FCAS or reduced delivery. As discussed in Section 2.3, while there is significant potential FFR capacity already in the NEM, current generation information[72] indicates several prospective large battery developments, in various planning stages, which may wish to offer FFR.

Regional requirements and maximum delivery caps

Regional requirements, either set at maximum or minimum volumes, would also help achieve geographic diversity and could improve system resilience, particularly for non-credible separations. Regional requirements are not currently a component of FCAS markets but have been raised as a potential future need[73].

National Grid developed the Enhanced Frequency Response (EFR) product, which requires providers to respond in 1 second or less. Tenders were limited to a maximum size of 50 MW to remove grid code concerns[74] but also to allow a wider range of projects to tender. The technical requirements for the service specified a droop envelope and maximum ramp rates[75]. National Grid has undertaken a process of rationalisation of its frequency services and EFR is no longer being actively procured[76]. The new National Grid Dynamic Containment product is similar in specification to what a Dynamic FFR service would be in the NEM.

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[71] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

[72] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[73] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

[74] See https://www.nationalgrid.com/sites/default/files/documents/Enhanced%20Frequency%20Response%20FAQs%20v5.0_.pdf.

[75] See https://www.nationalgrideso.com/sites/eso/files/documents/EFR%20Testing%20Guidance%20VD3%20%28Final%29.pdf.

[76] See https://www.nationalgrideso.com/sites/eso/files/documents/Product%20Roadmap%20for%20Frequency%20Response%20and%20Reserve.pdf.

The Dynamic Containment Product also has a 50 MW cap on individual units, out of an initial procurement of 500 MW, with an intended final aggregate procurement volume of 1,000 MW[77].

The application of regional and individual delivery caps would better allow AEMO and TNSPs to conduct FFR integration studies, so the responsibility for conducting these studies could then rest with AEMO and relevant TNSP rather than the market registrant.

4.1.2 RoCoF

High RoCoF may change how providers respond to frequency both for dynamic and switched provision, due to the way frequency is measured. Testing a provider's response to the RoCoF they are likely to experience for credible and non-credible events would verify that it will be able to deliver its registered volumes of service, within the specified time.

4.1.3 Technical requirements for Dynamic FFR

Frequency droop

Droop settings facilitate the sharing of frequency response between providers in response to a frequency event. They allow each unit to respond in accordance with their size, with the overall response being distributed between providers. Batteries are capable of setting very low droop values, giving large responses to small changes in frequency. Internationally minimum droop values, or maximum reactivity, are specified in grid codes in the range of 2-3%[78]. There is long-standing international experience with droop settings in this range. As the droop setting approaches 0%, or isochronous control, the provider would potentially swing its full capacity in response to any frequency disturbance within its band of frequency sensitivity. Wide adoption of very low droop settings has potential stability implications[79]. AEMO has set a minimum droop setting of 1.7% for battery providers of FCAS[80], unless otherwise specified.

Response speed

While FAPR in the order of hundreds of milliseconds is achievable[81], for dynamic FFR it is important that the response is related to frequency. Tuning of controls to deliver very rapid responses in advance of system frequency, may have detrimental system impacts including adverse control interactions and adverse stability outcomes. National Grid's Dynamic Containment product has a maximum response time of 0.5 seconds, as shown in Figure 12.

[77] https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/dynamic-containment?market-information

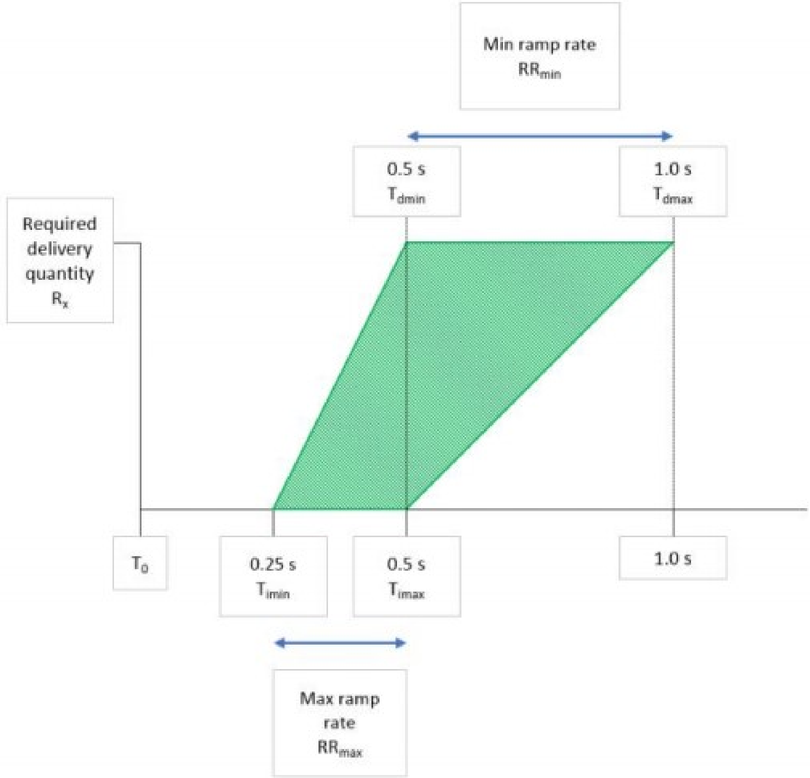
[78] See https://certs.lbl.gov/sites/default/files/international_grid_codes_lbnl-2001104.pdf.

[79] For example, see '*Impact of Frequency-Watt Control on the Dynamics of a High DER Penetration Power System*', Dinesh Pattabiraman et al, 2018 IEEE Power & Energy Society General Meeting (PESGM).

[80] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

[81] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-coversheet-20170310.pdf?la=en

Figure 12 National Grid, Dynamic Containment product response speed



Source: National Grid, at https://www.nationalgrideso.com/document/177091/download.

4.1.4 Technical requirements for Switched FFR

As outlined in Table 6, the characteristics of switched response are different to dynamic response, so it is appropriate to treat it separately for the purpose of volume specification.

Table 6 Characteristics of switched response

Limitations	Advantages
Continuous control: Switched FCAS is not continuously sensitive to frequency and so does not act to control it; rather, it gives it gives a discrete sized offset to power balance. While not explicitly valued by the MASS, the continuous control provided by frequency sensitive PFR, or governor-like control, is crucial to the operation of the power system. Some level of frequency-sensitive PFR is required for control of frequency during normal operation and in response to credible events. It is also required for UFLS and OFGS to operate effectively. Repeatability: Switched FCAS is a one-shot response. After it is triggered, it takes some time for it to be restored and re-armed. For complex events this allows some reserve to be tripped off that is then not available if needed later. Frequency-sensitive PFR will respond to the frequency as long are there is headroom and energy available for the response. If high penetrations of switched control were to replace frequency-sensitive PFR with headroom, it would reduce system resilience to complex events. Overprovision: As switched FCAS is a discrete sized MW response, in circumstances where less than the full amount is selected under the market an overprovision may occur if the full amount is delivered. This issue could be addressed to some degree by placing additional requirements on providers to manage the size of their response.	Speed: The fast power injection of some switched providers give it great potential to reduce R6 requirements under low inertia conditions. There is already a significant volume of switched response in the FCAS market and recognising the faster proportion of this response would likely allow for significant reduction in projected R6 volumes. Distributed response: A large proportion of switched response is provided by load response aggregators, so is geographically distributed. Ability to trigger on RoCoF: Switched response can trigger on RoCoF, helping to coordinate the switched response with PFR and UFLS and deliver a rapid response when it is required. Ability to sustain response: As switch response is often provided by the disconnection of load, is able to be sustained. Restoring system frequency: The static power injection provided by switched response assist in restoring system frequency in a way that droop based response cannot do. This is particularly important in the R5 time frame.

The need to maintain a minimum amount of dynamic response has been outlined in RIS Appendix B, and recorded as a work item on AEMO's *Frequency Control Workplan*[82]. A constraint is currently in place to manage the portion of fast FCAS in Tasmania that comes from switched reserve, and the 2021 MASS review is considering further arrangements to maintain a minimum portion of dynamic response[83].

The inclusion of switched response in an FFR service will require consideration of the different characteristics of switched provision, and the maintenance of a minimum level of dynamic response across the contingency FCAS services.

[82] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

[83] See https://aemo.com.au/en/consultations/current-and-closed-consultations/mass-consultation.

5. Transitional arrangements

FCAS require the reservation of headroom to operate (for some providers) and so benefit from co-optimisation with energy, and are suited to 5-minute markets. FFR, specified to fulfill the problem definition outlined in Section 1.3.3, would operate as an extension to existing FCAS. However, there are several aspects of FFR markets development outside of reserve-energy co-optimisation that should be considered. This section considers the need for transitional arrangements.

Key insights

- **FFR services, as an extension to FCAS, are suited to 5-minute markets** – provided locational limits and requirements can be managed in 5-minute markets, FFR can be implemented in these markets. The market impacts of these requirements should be considered in market design.
- **Out of market arrangements should be considered as a transitional measure** – the use of out of market procurement as a transitional measure would allow the service specification to be more readily refined in advance of market implementation. Coupled with locational requirements, it would also help minimise the technical integration challenges and allow procedures to be developed to manage these challenges in the initial stages of the market.

5.1 FFR service implementation process

The appropriate implementation process will depend on the form of final and transitional FFR arrangements made in the final rule; however, the successful development of an FFR service will initially require:

- Flexibility in service specification and scheduling arrangements, to allow for these arrangements be refined through experience.
- Certainty in volumes and location of FFR provision to allow for power system impacts be addressed prior to significant additional FFR volumes coming online.
- Making limitations on FFR provision visible to the market. As discussed in Section 4.1.1, there may be locational limits to FFR delivery that are not immediately evident, and integration issues that require detailed technical analysis to resolve. These limitations may not be fully definable at market start. This could potentially lead to the registered FFR volumes of newly developed projects (incentivised by the introduction of an FFR service) being impacted, if not adequately managed.
- Allowing for a gradual increase in maximum FFR volumes, and potentially widening range of scheduled FFR volumes and locational requirements. Gradual increase of FFR volumes would better allow for power system and market impacts to be assessed and managed.

As outlined below, out of market procurement could assist in addressing these requirements.

5.2 Out of market procurement as a transitional measure

It is expected that out of market procurement would be able to be developed more quickly than FCAS market integration, although this would depend on the detail of the out of market procurement arrangements as well as the details of the enduring market implementation. Learnings from initial out of market procurement would be expected to inform the development of market arrangements.

There are comparable examples of out of market procurement being used locally and internationally. National Grid, EirGrid, and Terna[84] have contact arrangements in place for procuring comparable services or are developing these arrangements. Contract arrangements form part of more complex procurement arrangements for Nordic FFR services[85]. Initial out of market procurement transitioning to 5-minute markets is also how the existing FCAS services were developed in the NEM.

5.2.1 Flexibility in service design

While there are existing uses for FFR in the NEM, including under the Minimum Inertia Requirements, the use of FFR as a market service for managing system intact conditions requires development of a detailed market service specification accounting for a specific set of operating conditions and interaction with other services, system parameters and processes.

Initial out of market procurement is expected to more readily allow for revision of services specification and other arrangements. This would allow for issues with the specification, delivery, testing and compliance to be worked through without having large market impacts. There is less flexibility for iterative service design once a market service has been established.

5.2.2 System security and resilience

As discussed in Section 4, locational concentrations of FFR could present security issues, and there are implementation challenges related to FFR that may not be easily anticipated by prospective FFR providers. Specifying a volume cap on individual units, as has been applied in the UK, would help minimise integration issues due to high locational concentrations, it would also help maintain geographic diversity and improve the reliability of the service by being less dependent on individual providers. It would also help minimise the risk of incentivising the development of FFR that is then limited in provision due to technical issues. Regional requirements will also promote development of FFR in appropriate locations.

It is conceivable that maximum individual provision and regional requirements could be included as part of 5-minute market arrangements, however the effect on market dynamics would need to be assessed. Out of market procurement, with locational requirements, could be used to minimise integration issues and maximise immediate security and resilience benefits. It is expected that it would also allow procedures to be developed to manage these challenges before transitioning to 5-minute markets.

Irrespective of the procurement mechanism, progressively increasing FFR volumes would better allow for power system and market impacts to be better managed. Progressive increasing requirements could be achieved in 5-minute markets, as was done recently for a change in load relief assumptions in the contingency FCAS market[86]. The feasibility of this would depend on the complexity of the scheduling mechanism and the interaction between FFR and R6/L6. As discussed in Section 3.1.1, this may involve simplified initial scheduling arrangements using a static volume of FFR, rather than inertia dependent volumes. If R6/L6 is needed in this transitional period to indirectly procure some FFR speed response while FFR volumes are increased, then respecifying R6/L6 to minimise overlap between these services and FFR (as outlined in Section 3.2.1) may need to be done separately to introducing FFR, requiring multiple MASS changes.

5.2.3 Discussion

Any contacting arrangement (or other out-of-market arrangement) for FFR would be time limited, with the purpose of assisting in an orderly transition to market arrangements. Implementing these transitional

[84] See https://download.terna.it/terna/Fast%20Reserve%20-%20Information%20pack_8d82fe02cbed7ad.pdf.

[85] See https://www.epressi.com/media/userfiles/107305/1576157646/fast-frequency-reserve-solution-to-the-nordic-inertia-challenge-1.pdf.

[86] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/load-relief/update-on-contingency-fcas-aug-2019.pdf?la=en.

arrangements would incur some cost and involve effort from the AEMC, AEMO and industry to develop. Complex out of market arrangements would be counter-productive, as they would add a significant additional step in developing an FFR market, rather than assisting with market development. Complex out of market arrangements would likely incur implementation and operational costs not commensurate with time limited interim measures, likely used for procurement of lower service volumes. The scale and scope of any transitional measures should be considered with reference to their purpose in assisting market implementation.

Irrespective of how FFR is procured as it is introduced, gradually increasing FFR volumes would be appropriate. While this transitional measure does not resolve all possible integration issues, it would allow AEMO to progressively assess FFR introduction and respond if power system or market issues become evident.

6. Market implementation options

Assuming that FFR is implemented as an extension to the existing contingency FCAS services, following appropriate transitional measures and development, there are several options on how this could be implemented. The AEMC's Directions Paper[87] outlines a range of options for the implementation of FFR in the NEM. These include:

- Option 1: Introducing a new market ancillary service to procure FFR FCAS.
- Option 2: Reconfiguration of the existing FCAS arrangements to procure FFR.
- Option 3: The use of differential pricing enabled through the application of scaling factors that reflect varying levels of performance from individual providers.

This section reviews the system security, operability, implementation, transparency, and efficiency aspects of these three proposed options. For comparison, continuing the management of frequency for the NEM intact without FFR is also examined. This baseline option makes use of inertia dependent R6 FCAS to contain frequency under low inertia conditions.

Key insights

- **FFR services should be developed for managing frequency containment under system intact conditions** – in the longer term, inertia dependent R6/L6 will be an indirect and inefficient way to ensure the required speed of frequency response under lower inertia conditions. Introduction of an FCAS-like FFR service would allow the existing speed capability within current FCAS providers to be recognised, and allow new providers to assist in reducing R6/L6 volume requirements.
- **FFR and R6/L6 services should not be combined**– combining FFR and R6/L6 would exclude some R6/L6 providers from offering into the combined fast contingency services. Response capability that is suitable for R6/L6, but is too slow for FFR, is useful at high inertia when higher volumes of FFR speed services are not needed.
- **R5/L5 services should not be combined with other services**– R5/L5 fulfill a different role in the market, by assisting in frequency restoration, and should not be combined with other services used solely for frequency containment.
- **Market participants should be consulted on combining R6 and R60 services** – while there does not appear to be a large number of providers delivering R6 responses that cannot be sustained into the R60 timeframe, there is a significant level of use of 6-second and 60-second services that would be affected by consolidating these services, as well as a limited number of providers that are registered in one service but not the other.
- **Speed of FFR should not be incentivised with volume multipliers at registration** – crediting FFR with greater volume for faster delivery at registration will complicate scheduling the correct volume of services.

[87] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf.

- **Introduction of speed factor parameterisation is not recommended at this time** – speed factor parametrisation of FCAS provision would require significant development in the NEM context. The likely complexity of speed factor parameterisation in the NEM context would extend implementation time and costs and potentially limit flexibility to make future changes. This application of this approach in the NEM may not provide market outcomes as transparent as other approaches, or provide clear signals on the required speed of response.

6.1 Baseline option: Inertia dependent R6 FCAS (without an FFR service)

6.1.1 Concept

Currently, AEMO intends to extend inertia dependent FCAS volumes to the management of generation and load events (credible contingencies) for mainland intact operation. This is currently scheduled to commence in Q4 2021. FCAS volumes are managed using constraint equations applied in NEMDE[88]; as of the date of this report, AEMO has not completed the detailed work to formulate the inertia dependent FCAS constraint equations. However, in general terms:

- R6/L6 volumes would increase as inertia decreases.
- R60/L60 and R5/L5 volumes are expected to remain relatively static as a result of this change.

This is considered a baseline solution, as it is currently planned to be implemented in some form, independent of the rule change process.

6.2 Inertia-FCAS relationship

As outlined in RIS Appendix B, the relationship between the R6 requirement and inertia is dependent on the frequency responsiveness of the FCAS providers.

Under current market arrangements, R6/L6 contingency FCAS is measured across 6 seconds. In valuing PFR, the MASS uses a standard frequency ramp. In response to this ramp, the MASS sets a baseline PFR response that is a straight line increasing in active power from the time the frequency crosses the NOFB up to the maximum response 6 seconds after the NOFB crossing time. The standard frequency ramp and baseline response are shown in Figure 13.

In practice, most proportional FCAS providers have a dynamic response that is dependent on the frequency profile of each event. If frequency is falling faster, they will respond faster, limited only by the time constants associated with the plant.

In contrast, the PFR baseline represents a response to one specific frequency profile as defined in the MASS. The behaviour of the plant for faster or slower frequency excursions is not specified by the MASS.

The response of a dynamic lumped model has been compared to the baseline MASS response in Figure 14. The dynamic lumped model is representative of a PFR type response, weighted towards the responsiveness of the large thermal FCAS providing generators.

[88] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/constraint_formulation_guidelines_v10_1.pdf.

Figure 13 MASS standard under-frequency ramp used to assess raise services

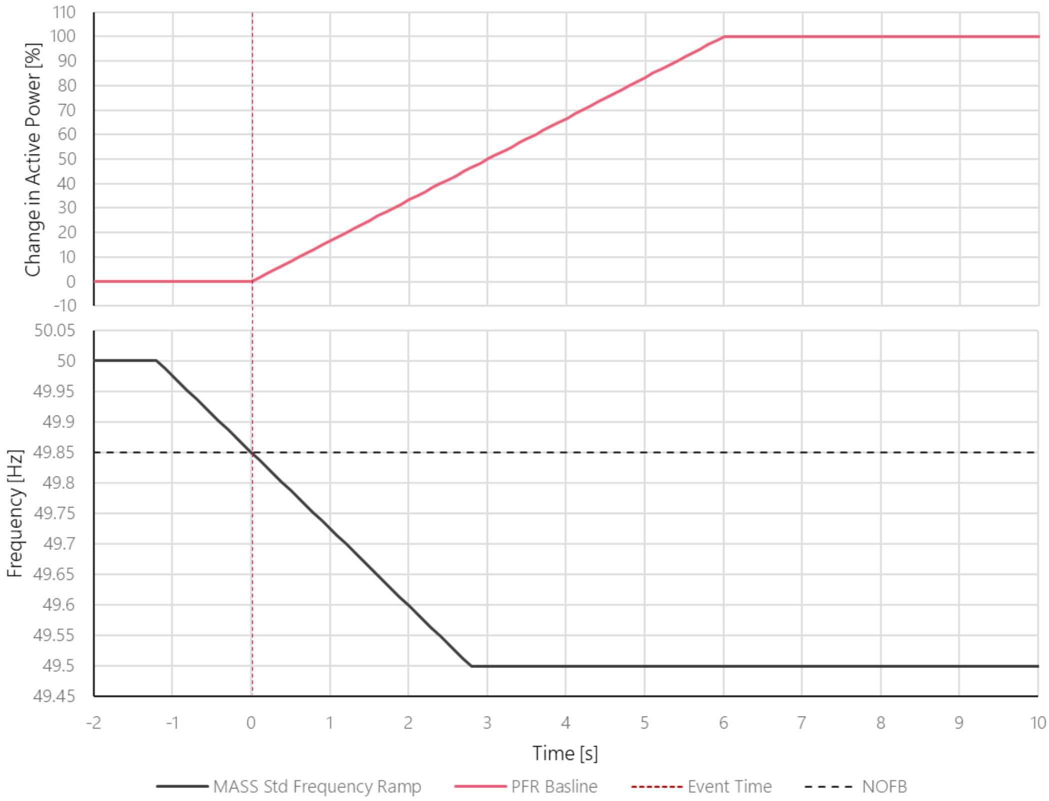
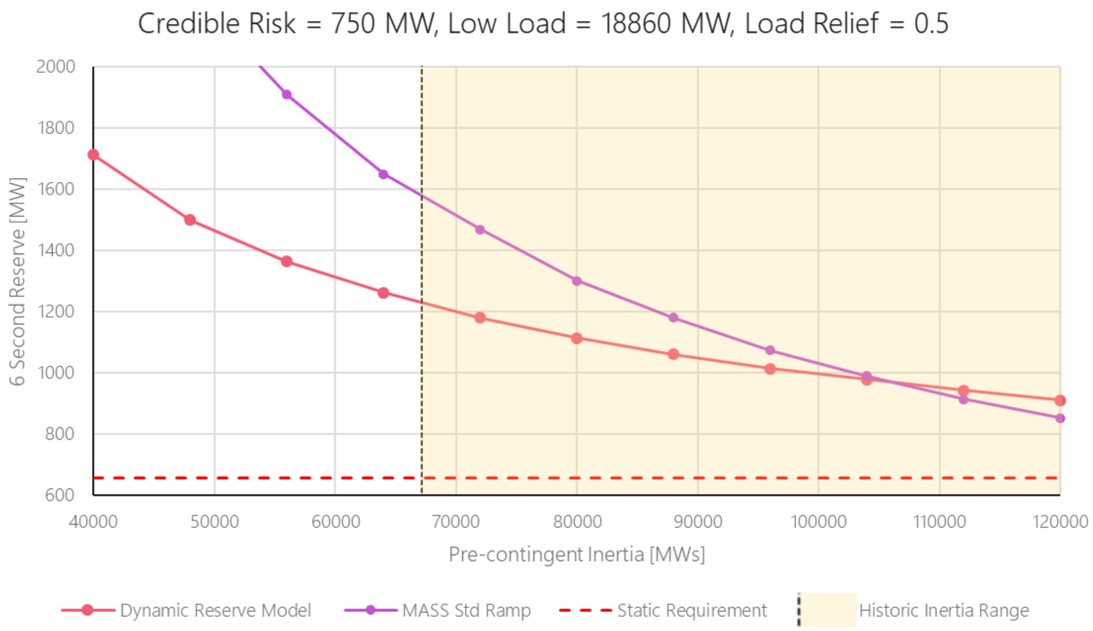


Figure 14 Dynamic model response compared to MASS baseline requirement (low load)



The extent to which the dynamic model shows lower reserve requirements than the MASS representative ramp model depends on the time constants modelled. In reality, the time constants of individual generators will vary so the response of the system will vary depending on dispatch. Generators that are also FCAS providers should provide a response that is consistent with the Interim Primary Frequency Response

Requirement (IPFRR)[89], not only the MASS, and so should not limit their response to the baseline MASS response.

The extent to which constraints that set FCAS volumes will be able to account for the dynamic characteristic of PFR provision will be addressed as part of their implementation. It may be appropriate for this to be reviewed over time as experience in inertia dependent FCAS is gained. For the purpose of this report, both sets of curves should be viewed as indicative of the range of the potential inertia-R6 relationship used for setting R6 volumes. The dynamic-model curve has been used for other sections of this report as it is expected to be a closer representation of the true power system requirements, rather than a result of the existing market constructs.

For consistency, the inertia-R6 requirement curves shown in this report are at one risk size and load level. This is illustrative of one scenario, but R6 requirements are dependent on risk size, load and inertia. The low load condition is a more onerous condition as there is less load damping, so higher FCAS requirements. In practice, inertia and load level are correlated.

6.3 Evaluation of the baseline option

Table 7 Inertia dependent R6 FCAS (without an FFR service)

Consideration	Advantages	Disadvantages
System security and operability	Expected to be able to maintain system security over the short to medium term. Scheduling of required services managed through constraints.	Under very low inertia conditions there could be potential R6 shortfalls if large volumes were to be required without sufficient capacity in the market.
Implementation	Inertia dependent FCAS volumes are already implemented for management of islanded regions. Implementing inertia dependent FCAS for system intact would extend this practice to the usual system condition.	
Simplicity and transparency	This development maintains the existing contingency FCAS market services, which are well understood by industry.	
Efficiency		• Inefficient reserve volume – this approach is expected to require much greater volumes of R6 compared to those needed historically. As the required speed of response is sourced indirectly through procuring greater volumes of R6 FCAS, this approach is not expected to be as efficient as a more direct approach to ensuring the required response speed. This approach will require the holding of greater headroom capacity on FCAS providers that isn't required for managing the credible risk, and this may affect the energy market. • Scheduling efficiency should risk size co-optimisation be introduced – considering inertia when calculating R6 volumes impacts on the ability for risk size to be co-optimised with FCAS accurately using linear constraint equations, due to the non-linear relationship (particularly at low inertia).

[89] See https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en.

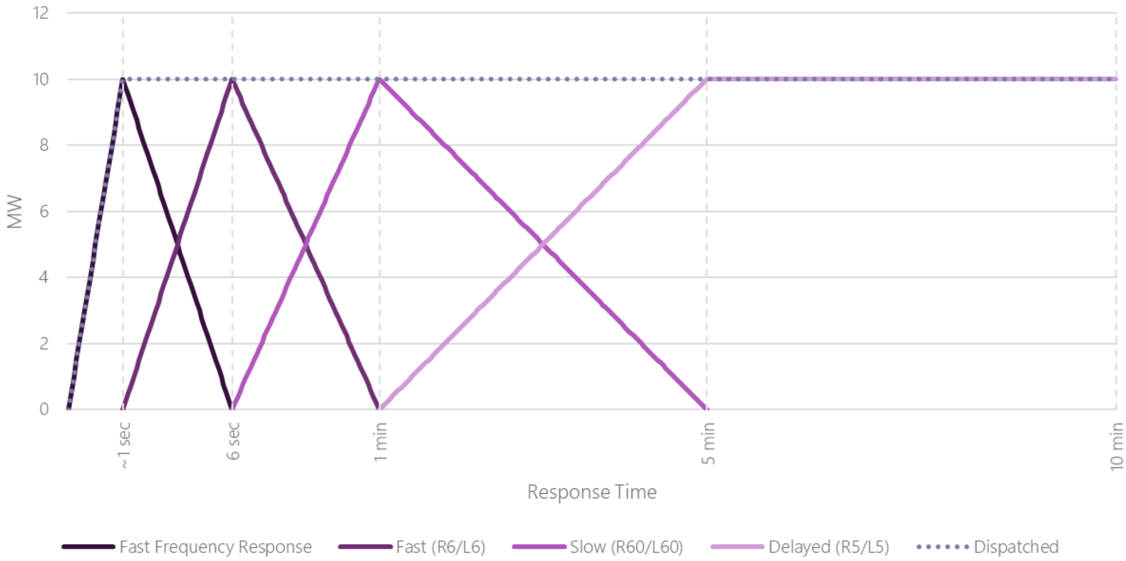
6.4 Option 1: FFR raise and FFR lower added as separate contingency FCAS

6.4.1 Concept

The speed of PFR is a continuum across technologies and individual plants. Batteries, IBR more generally, and switched load represent the faster end of this range, often termed FFR. This faster response can lower the R6/L6 requirements under low inertia conditions[90]. There is a significant portion of faster than R6/L6 response already present in the market, however the speed of this response is not recognised in a way that allows faster providers to be scheduled independently of R6/L6 to minimise volumes based on the system requirements.

Introduction of FFR raise and FFR lower services, as additional contingency FCAS services, would allow this faster response to be recognised in setting R6/L6 volumes as well as rewarding the speed of this response. Figure 15 shows a conceptual view of the proposed new service alongside the existing service. The 6-second service (R6/L6) has been amended from the current specification to start later, avoiding overlap with the FFR service. This is discussed further in Section 3.2.

Figure 15 Additional FFR services as part of suite of FCAS services



6.5 Efficiency

Under the baseline option, the greater volumes of R6 required to arrest frequency under low inertia are needed to ensure the active power response is fast enough, rather than there being a requirement for a greater magnitude of response. Scheduling greater volumes of R6 is successful in arresting frequency under low inertia as it indirectly procures some response faster than 6 seconds. This approach would require the holding of greater headroom capacity on FCAS units than required for managing the credible risk, and this may affect the energy market.

Introducing an FFR service is a more direct approach to ensuring the required response speed and does not require the holding of unneeded reserve headroom.

[90] See https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

6.6 Implementation

Implementing FFR as an extension to the existing contingency FCAS services may require:

- Development of FCAS constraints to schedule FFR.
- NEMDE changes related to energy/FCAS co-optimisation arrangements.
- Changes to the settlements systems and processes.
- Registration of FFR providers and associated testing and compliance measures.
- Amendment to MASS specification for R6/L6 and potentially changes to existing FCAS registered volumes.

The implementation process will be dependent on the final rule made. As a high-level estimate, based on previous experience with market system changes, AEMO estimates that the implementation would be in the order of three years. This implementation would include:

- Engineering work on FFR service definition including telemetry and data recording requirements.
- Engineering work on the scheduling arrangements for FFR services, including FCAS constraint development.
- Market system and IT system changes, including NEMDE changes.
- Consultation with industry, including consultation on MASS changes.

6.7 Evaluation of Option 1

Table 8 FFR raise and FFR lower added as separate contingency FCAS

Consideration	Advantages	Disadvantages
System security and operability	• Provided the technical requirements for FFR provision as outlined in Section 4 are managed, this approach is able to maintain system security. • FFR can be scheduled by FCAS constraints.	
Implementation		• As the implementation requires the introduction of new contingency FCAS, it will require changes to market system components. • New constraints will be required to schedule the new service. • Some changes to existing FCAS services specifications (MASS) are likely needed to accommodate the FFR service. • Implementation time and cost would be more substantial than the baseline option.
Simplicity and transparency	Extends the existing contingency FCAS market services, which are well understood by industry.	
Efficiency	• Directly recognises the required speed of response. • Recognises and rewards the existing FFR capacity within FCAS market participants, which is expected to be significant.	

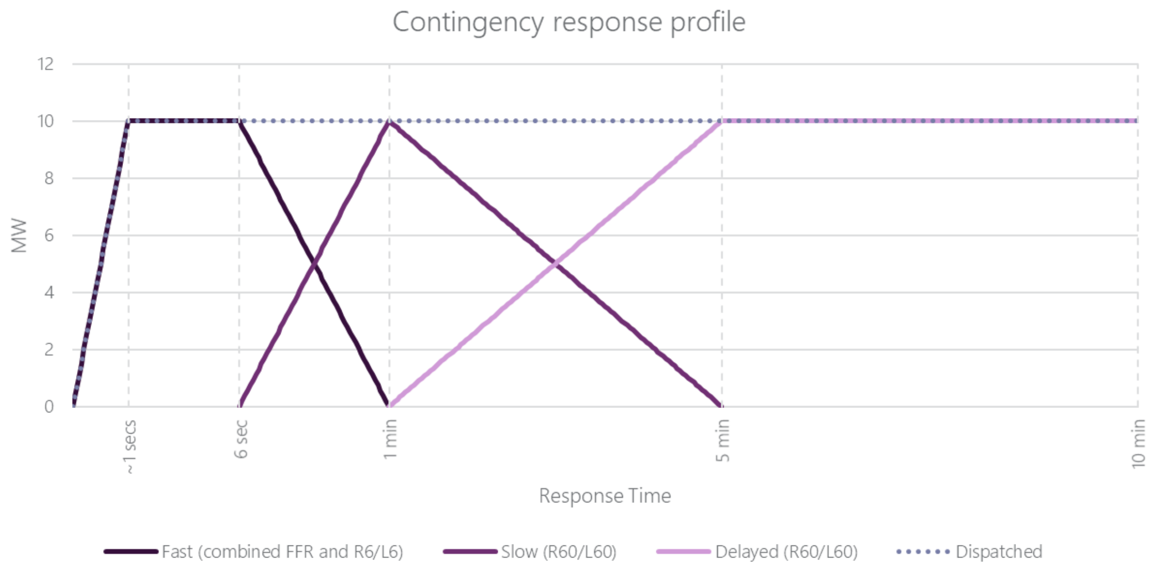
6.8 Option 2: Introduce FFR by re-specifying existing FCAS products

6.8.1 Concept

By reconfiguring the existing contingency FCAS service, the total number of services could be kept the same, three raise and three lower, while allowing faster responses to be procured. This option has been outlined by the AEMC in the Directions Paper.

As a strawman proposal, the AEMC has raised the prospect of consolidating FFR and R6/L6 services on the introduction of FFR, to keep the number of overall services the same[91]. This option is shown in Figure 16.

Figure 16 AEMC's strawman proposal on consolidation of fast services



This outlines one potential option; however, there are several possible options to consolidate services, including:

- Combining the proposed FFR service with the R6/L6 service.
- Combining R60/L60 with R5/L5.
- Combining R6/L6 with R60/L60.

As explained in the following sections, the first two sub-options are not suitable given the differences in the use of those services in the NEM. Subject to implementation and impact considerations, it would be feasible to combine 6-second and 60-second services in a single category (the third sub-option). This is discussed in more detail below.

6.8.2 Overview of existing service participation

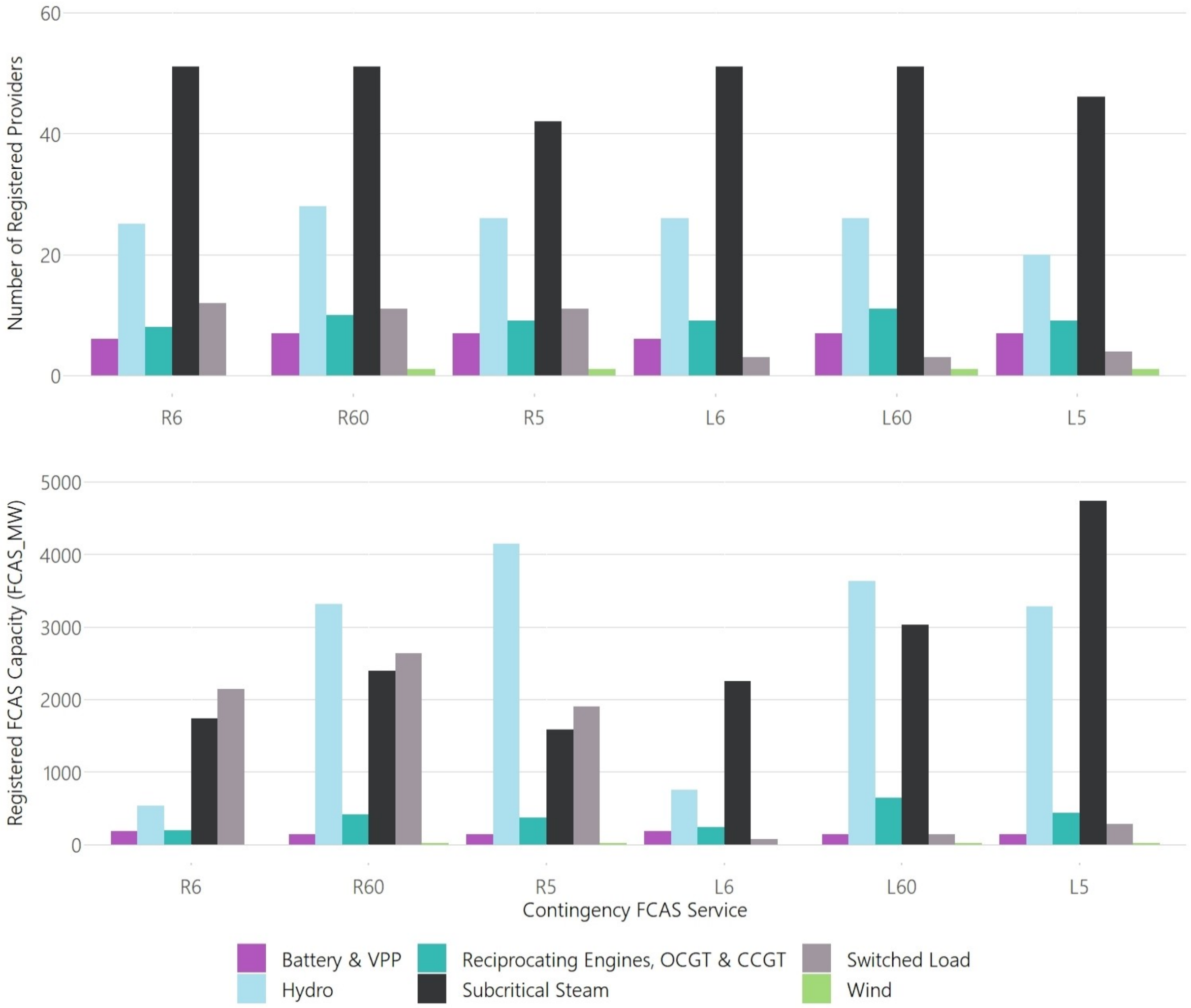
This analysis includes any FCAS provider that has been enabled between 1 October 2019 and 1 October 2020 and is registered for at least one of the six contingency FCAS markets over that period. There are 113 providers registered for provision of at least one contingency FCAS service in the NEM. Table 9 shows the total volume of participants registered in each service. Figure 17 shows the number and volume of registered providers in each FCAS service by technology type.

[91] See https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20-%20Technical%20working%20group%20-%208OCT2020-FINAL%20for%20publication.pdf.

Table 9 Registered FCAS capacity

	R6	R60	R5	L6	L60	L5
Total FCAS_MW	4,790	8,904	8,161	3,495	7,594	8,905
Number of providers	102	108	95	94	98	86

Figure 17 Registered providers and capacities for contingency FCAS services by technology type



6.8.3 Potential consolidation of R60/L60 and R5/L5

The purpose of delayed raise and delayed lower services is to assist in returning the system frequency to 50 Hz within the first five minutes of a frequency disturbance that resulted in system frequency being outside the NOFB[92]. It has traditionally been provided by manual load reduction and starting up hydroelectric or gas generating units[93]. To assist in frequency restoration, some L5/R5 service providers may drive their active

[92] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/primary-freq-resp-norm-op-conditions/market-ancillary-services-specification---v60.pdf?la=en&hash=4E46BE456C8D1DEAF12D0FF922DE4DBA.

[93] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/primary-freq-resp-norm-op-conditions/market-ancillary-services-specification---v60.pdf?la=en&hash=4E46BE456C8D1DEAF12D0FF922DE4DBA.

power setpoint, to achieve an increase or decrease in output separate to, or in addition to, droop type response. Currently, delayed FCAS is co-optimised with regulation FCAS, with the volume of delayed being reduced based on regulation FCAS volumes.

Due to the different form of response used in delayed FCAS provision and the different role delayed services play in the market, it is not suited to consolidation with R60/L60.

6.8.4 Potential consolidation of FFR and R6/L6

A services specification with an FFR response time (~1 second response) combined with the existing R6/L6 specification is likely to exclude a large proportion of existing R6/L6 providers. While FFR capable technologies including batteries, load response, and potentially solar generation can sustain responses into the R6/L6 time frame, many thermal units and hydro units currently registered in the 6-second services would not be able to provide a comparable magnitude of responses in the FFR time frame.

Greater volumes of the FFR service would be needed under low inertia conditions, so combining the FFR with R6/L6 would likely procure unnecessary volumes of faster response. Accordingly, the R6/L6 service is not suited to consolidation with FFR.

6.8.5 Potential consolidation of R6/L6 with R60/L60

To analyse the potential of combining the 6-second and 60-second services, as displayed in Figure 18, both market registration data and market FCAS availability and enablement data have been used. The volume of providers that offer exclusively into one of the two services was analysed, as well as the relative difference in the volume of service offered for providers who offer into both R6/L6 and R60/L60. This analysis is contained in the subsequent sections.

Figure 18 Consolidation of R6/L6 and R60/L60

6.8.6 Exclusive registration R6/L6 or R60L60

Raise response

Table 10 shows how providers registered for R6 and R60 have their response segmented across the existing raise services. A majority of providers are registered for all three raise services.

Table 10 Service segmentation of R6 and R60 providers

	Providers registered in all three raise services	Providers registered exclusively in R6	Providers registered exclusively in R60	R6 and R60 but not R5	R60 and R5 but not R6
Total FCAS_MW	R6: 4,239 R60: 7,595 R5: 7,456	R6: 116	R60: 50	R6: 435 R60: 608	R60: 651 R5: 671
Number of providers	87	2	1	13	7

R60 and R5 registration (but not R6)

There is a group of seven providers that are registered for R60 and R5, but the speed of their response means they do not offer into the fast R6 service. This group is relevant to the feasibility of combining the R6 and R60 services without material impact on existing participants. There is 651 R60_MW registered in this group, or 7% of the total registered R60 volume, which may not be transferable to a consolidated R6-R60 service. This group contains response from hydro, wind, VPP and open-cycle gas turbine (OCGT) providers. This group does not have high R60 availability. Some volume of R60 is available from this group 1.3% of the time, with an average available volume of 3.5 R60_MW.

Exclusive R6 or R60 registration

There is a small group of providers within the raise contingency services that are exclusively registered in R6 or R60. One OCGT and one switched load are registered for R6. One closed-cycle gas turbine (CCGT) is exclusively registered for R60. The two exclusive R6 providers frequently have R6 availability. Some volume of R6 is available 51.7% of the time from this group, with an average available volume of 73.7 R6_MW. The exclusive R60 provider also frequently has availability, Some R60 volume from this provider is available 23.5% of the time with an average available volume of 21.2 R60_MW.

Lower Response

Table 11 shows how providers registered for L6 and L60 have their response segmented across the existing lower services. A majority of providers are registered for all three lower services.

Table 11 Service segmentation of L6 and L60 providers

	Providers registered in all three lower services	Providers registered exclusively in L6	Providers registered exclusively in L60	L6 and L60 but not L5	L60 and L5 but not L6
Total FCAS_MW	L6: 3,233 L60: 6,915 L5: 8,604	L6: 41	L60: 50	L6: 221 L60: 548	L60: 81 L5: 101
Number of providers	80	2	1	12	5

L60 and L5 registration (but not R6)

There is a group of providers that are registered for L60 and L5, but the speed of their response means they do not offer into the L6 service. This group is relevant to the possibility of combining the L6 and L60 services. There is 81 L60_MW registered in this group, or 1% of the total registered L60 volume, which may not be transferable to a consolidated L6-L60 service. This group contains response from hydro, wind, VPP, and OCGT providers. This group does not have high volumes of L60 availability. L60 is available from this group 1.9% of the time with an average available volume of 6.9 L60_MW.

Exclusive L6 or L60 registration

There is a small group of providers that, within the lower contingency services, are exclusively registered in L6 or L60. There are two providers offering exclusively L6 (one OCGT and one hydro generator). There is also one provider offering exclusively L60 (CCGT). The two exclusive L6 providers do not have significant L6 availability, L6 being available 1.7% of the time with an average available volume of 5.3 L6_MW. The exclusive L60 provider has greater availability. For this provider, L60 is available 24.7% with an average available volume of 48.2 L60_MW.

Discussion

There are only a small number of providers operating in 6-second or 60-second services, but not both. Of this group, a smaller set have significant FCAS availability in these services. Exclusive enablement for either 6-second or 60-second services is further examined below.

6.8.7 Exclusive enablement for R6/L6 or R60/L60

Providers may be registered for both 6-second and 60-second services but may only be enabled for one service in any given market interval. The volumes of FCAS enabled by providers in the 6-second services, without 60-second service provision, or in the 60-second service, without 6-second service provision are displayed in Table 12.

Table 12 Exclusive enablement of 6-second and 60-second services

Service	Min (FCAS_MW)	Max (FCAS_MW)	Ave (FCAS_MW)	Max (%)	Ave (%)
R6	0	84	27	16	4.9
R60	0	57	2.3	9.0	0.38
L6	0	16	0.18	17	0.082
L60	0	28	1.4	12	0.43

Discussion

Only a small volume of FCAS comes from providers that are selected for the 6-second or 60-second service but not both. However, it is not only the service participation that indicates the potential to consolidate services as providers may offer different volumes of FCAS into each service. This is discussed in more detail below, with a focus on the raise service.

6.8.8 Co-provision of R6 and R60

For the providers that are registered in both R6 and R60, and selected for both services, there are further considerations on the impact of consolidating these services. In most cases a singular continuous response from these providers is valued in the R6 and R60 services. The form of this response could be:

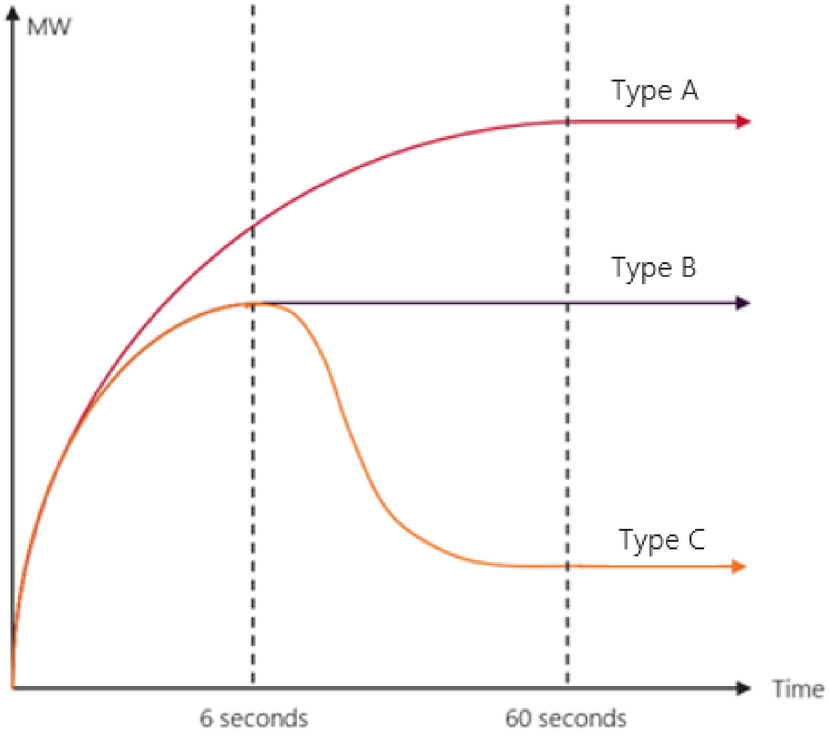
A. A response that achieves partial response in the R6 time span and can provide greater response into the R60 time span.

B. A response that achieves full response in the R6 time span, and can sustain that response into the R60 time span.

C. A response that achieves a maximum value in the R6 time span, but that is not fully sustained into the R60 time span.

An illustrative representation of these forms of response is shown in Figure 19.

Figure 19 Sustained and non-sustained responses



The split in providers between these two forms of response informs the impact of consolidating these services. If many providers are in Type C, it suggests there is a need for an R6 service that does not have to be sustained into the R60 time frame, in order to value a significant portion of faster response. It would also suggest that there is a need to separately value an R60 response that can come in after R6 and replace the energy of FCAS providers that could not be sustained (Type A).

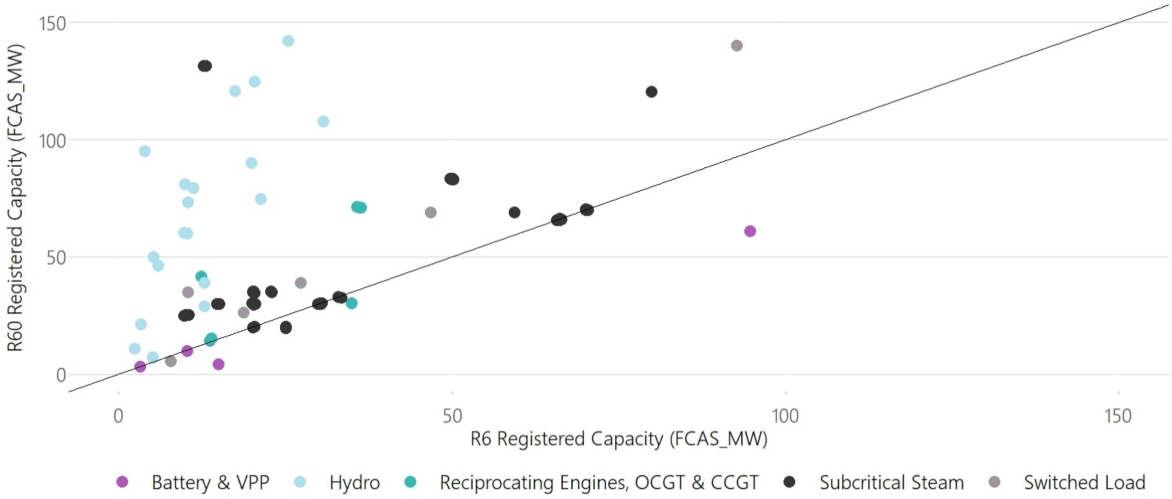
If most providers are in Type A or Type B, then a service specification that values a response that achieves an FCAS value in the R6 time frame and requires that response to be sustained into the R60 time frame can be considered. While there may be some providers that can offer additional response in the R60 time frame, this would only have significant value if it is required to replace a response that could not be sustained.

To investigate if the current market is made up of Type C R6 responses that are then replaced by separate R60 type responses, or is made up of responses that are continuous but valued under the separate R6 and R60 services (Type A or Type B), both registration data as well as market enablement and availability data has been used.

Registration data of R6 and R60 providers

Figure 20 shows the registered R6 value plotted against the registered R60 value for providers that offer both services. As the registered R60 values are greater than the registered R6 values in most cases, the registration data is suggestive of Type A or Type B responses from most providers. The providers that show higher R6 values are mostly faster providers, and the higher R6 value is due to having a higher registration value than instantaneous 6-second response, that can occur for faster providers under the existing MASS definitions[94].

Figure 20 Comparison of R6 and R60 registered FCAS capacities by technology



While the registration value is suggestive of the form of response, it is a maximum capacity. Providers may configure their plant to deliver FCAS in different ways, and could conceivably set their plant to achieve a maximum R6 response that is not sustained into the R60 time frame. Further analysis of the usage of the 6-second and 60-second service segmentation using FCAS availability market data is provided in Appendix A2.

6.8.9 Discussion on consolidation of R6/L6 with R60/L60

Analysing the registration and market data to ascertain whether there is a high level of use of the 6-second services to value responses that are not sustained is complicated by the way FCAS is valued. As fast responding R6/L6 providers can be registered for a greater volume of FCAS than their instantaneous provision at 6 seconds, an R6 value that is higher than an R60 value could be the result of either a fast R6 response, or an R6 response that is not fully sustained into the R60 timeframe. Additionally, service volumes are measured differently depending on whether they are provided at the same time as other services, or independently. When 6-second and 60-second services are provided by an individual provider concurrently, the volume of the 6-second service can limit the maximum volume of the 60-second service.

However, both the registration data and FCAS market enablement and availability data (Appendix A2) suggest there is not a high level of use of the R6 service to value responses that are not sustained. The use of R60 from providers that are not registered in R6, and the use of R6 from providers that are not registered in R60, is also small.

While the market data suggests that there is potential for consolidating the 6-second and 60-second services, the impact on any individual provider has not been accurately quantified. FCAS providers have the greatest knowledge about the capabilities of their plant and how they utilise the existing services. Consolidation of products would need to be predicated on consultation with existing FCAS providers.

6.8.10 Implementation

From a market systems implementation perspective, reconfiguration of the existing FCAS arrangements to procure FFR is preferable to introducing a new product, as it would minimise changes. It would keep the

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[94] See https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

existing number of FCAS constraints and use existing FCAS-related NEMDE components. Changes to the settlements systems and processes are also expected to be minimal, if required. After implementation, maintenance and operation of the FCAS market infrastructure is also kept simpler, with reduced number of services.

The logistics of transferring from a current set of services to the reconfigured set of services would require planning. Transitioning to new service specifications would also affect existing participants who would need to change their registered capacity to reflect their capabilities in accordance with the revised service specifications. While this would also be required for R6/L6 providers wishing to register to provide a separate FFR service under Option 1, that would be a smaller change with lower impact on existing FCAS providers.

Implementing FFR by reconfiguring the existing services would require;

- Changes to FCAS constraints to schedule FFR and new sustained 6-second service.
- Registration of FFR providers and re-registration of 6-second and 60-second service providers and associated testing.

6.8.11 Evaluation of Option 2

Table 13 Combining 6-second and 60-second products

Consideration	Advantages	Disadvantages
System security and operability	• Provided the technical requirements for FFR provision (as outlined in Section 4) are managed, system security can be maintained. • FFR can be scheduled by FCAS constraints.	
Implementation	Minimises changes to market systems, settlement and constraints, as compared to introduction of new product.	Changes to the registration of 6-second and 60-second service providers and associated testing required.
Simplicity and transparency	Minimises the number of FCAS services, reducing market segmentation and complexity.	
Efficiency	• Directly recognises the required speed of response. • Recognises the existing FFR capacity within FCAS market participants, which is expected to be significant.	Some provision from existing 6-second and 60-second providers will be affected.

6.9 Option 3: Differential pricing and scalar multipliers

6.9.1 Concept

In the Directions Paper, the AEMC outlines the concept of differential pricing for FFR, which would be enabled through the application of scaling factors that reflect varying levels of performance from individual providers. The AEMC cites two examples of differential pricing – the arrangements currently used in Ireland and the proposed arrangements for Western Australia. There is also a form of scalars applied in FCAS markets currently.

The use of these types of scalars in the context of introducing FFR services in the NEM is explored below.

6.9.2 The existing use of scalars applied in FCAS

The current MASS already applies a form of speed scalar to each service by calculating twice the time average in response over the service time interval. In valuing PFR, the MASS uses a standard frequency ramp. In response to this ramp, the MASS sets a baseline PFR response that is a straight line increasing in active power from the time the frequency crosses the NOFB up to the maximum response 6 seconds after the NOFB crossing time, as shown in Figure 13. The extent to which the provider's average response is above or below this baseline sets how much their registered FCAS value is above or below their instantaneous 6-second output.

The result of this design is that faster providers may be registered for FCAS MW values significantly above their actual instantaneous MW provision. These may cause a deficit in the volume of FCAS scheduled, as the scaling factor is applied to registered volume. The issue is further discussed in RIS Appendix B.

It is conceivable to apply a simple scalar to price, rather than registered volumes. This would reward faster provision, but would not allow this value to be recognised to reduce overall requirements in scheduling service volumes. To both reward faster provision and utilise the value of this speed, a more complex approach is required, such as the mechanism under development for the Wholesale Electricity Market (WEM) in Western Australia.

6.9.3 Overview of future WEM arrangements

The Future Market Design and Operation project is developing Essential System Services (ESS) for the WEM, as part of the Western Australian Government's Energy Transformation Strategy[95]. A subset of the services under development are the Contingency Reserve services, fulfilling a similar market function to the contingency FCAS markets in the NEM. Speed factors form part of the design for these services. These services are still under development.

The WEM currently has two time segments in the Contingency markets – a 6-second and a 60-second service. The introduction of speed factors will replace these two services with a single service, but with an individual speed factor assigned to each facility, which relates to the characteristics of facility response to frequency deviation including response time.

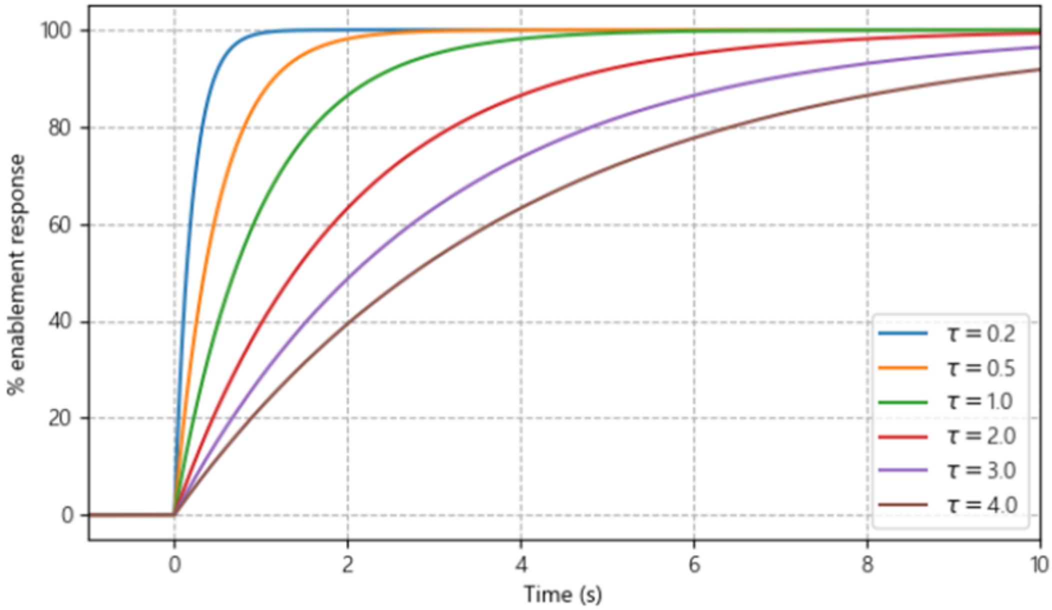
Figure 21 shows an example of how speed factors (Tau [τ]) may be calculated from response curves, with the faster a facility can respond, the smaller the Tau factor assigned. Tau factors are assigned by relating a facilities actual response to a modelled response represented by the equation:

$$\text{Response} = \text{Reserve\_MW} \times (1 - e^{-\frac{t}{\tau}})$$

These curves approximate the most critical turbine dynamics of synchronous machines and can be generalised to fast electronic or switched responses through very small speed factors. An example of relating the modelled response to a gas turbine response is shown in Figure 22.

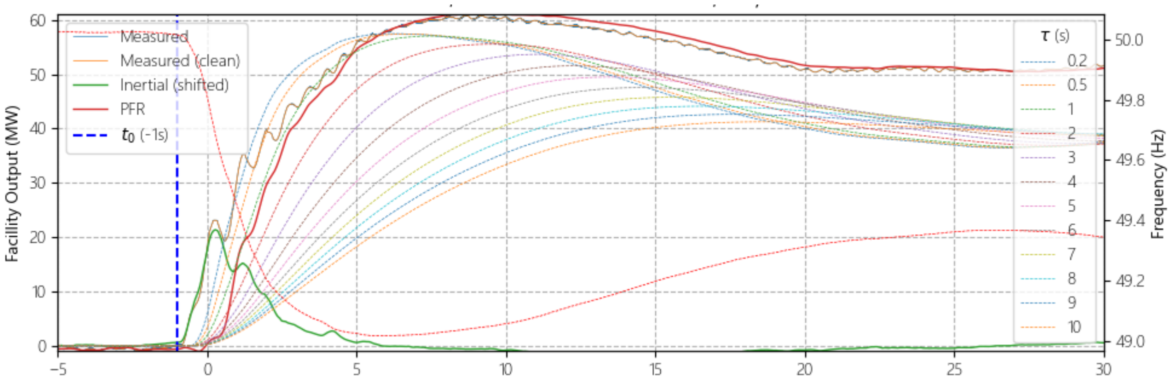
[95] See https://www.wa.gov.au/sites/default/files/2019-12/Information%20Paper%20-%20ESS%20Scheduling%20and%20Dispatch%20_final.pdf.

Figure 21 Example translation of response curves to speed factors



Source: Energy Transformation Task Force, at https://www.wa.gov.au/sites/default/files/2019-12/Information%20Paper%20-%20ESS%20Scheduling%20and%20Dispatch%20_final.pdf.

Figure 22 Example of modelled and actual response.



In this approach, a power system model pre-calculates the required volumes at each response speed over the range of other relevant parameters:

- System inertia.
- System load (load relief).
- Contingency risk size.

For example, for a given contingency risk under low system inertia and system load conditions, frequency stability can be maintained with a lower volume of faster (lower speed factor) response. Conversely, at high inertia and system load, a fast response is no longer required to prevent breaching of frequency limits, and the volumes across speed factors begin to equalise.

The dynamics aspects of these relationships are linearised through the selection of small step sizes for each of the parameters. The result is many thousand combinations; however, each scenario reduces to a single value: the required volume at response speed τ. These volumes are converted into scalar performance factors that weigh the relative value of speed (in direct proportion to required volumes) for a given dispatch interval. The performance factors may then be incorporated into a standard linear dispatch optimisation.

While system load is generally outside control of the dispatch process, scheduling of volumes for contingency services incorporates real time co-optimisation contingency risk size and a separate ESS market for inertia, along with procurement of the required volumes of contingency response service.

6.9.4 The applicability of speed factors to the NEM

There are a number of physical differences between the WEM and the NEM that affect frequency management. The nature of the frequency containment problem faced in the WEM is much more acute.

The WEM has a risk size of ~340 MW, and a system size of ~5 gigawatts (GW) peak. The NEM has a risk size of ~750 MW and a system size of ~36 GW peak. The WEM has to manage a large risk comparable to the available inertia, and with a more limited set of resources. The NEM has 70 individual FCAS providers, while the WEM has 35 frequency ancillary service providers. With a more acute issue and limited number of service providers, the individual parameterisation of response in the WEM creates the opportunity to achieve significant efficiencies with manageable increases to market complexity.

While the NEM is a much larger system than the WEM, the propensity of regions to island in the NEM creates its own challenges. The FCAS system need to be able to support the system intact and operation and the operation of islanded regions.

6.9.5 Parametrisation of FCAS provider response

Consolidation of existing speed segmented services

Currently FCAS providers may provide different forms of response depending on selection under each of the market segments. Separate to providing a droop response, slower services providers may drive their active power setpoint, particularly in the delayed service but also this is also done for some fast and slow contingency FCAS. This practice is beneficial in restoring frequency and allow providers to maximise the value of their response. Speed factors would not allow for a single service across all three of the existing NEM time segmentations, as delayed response would still need to be separated due to this different type of response. Where this form of control is used in the slow and fast service it may complicate speed factor assignment. Different forms of control would also be seen from fast start providers who can act as fast units triggered to come online, or hydro units trigged to increase output from Tail Water Depressed mode.

Accuracy of parametrisation

The assignment of a speed factor to an individual facility could be based on site tests, real event performance or modelling. Injecting a frequency signal into a plant's frequency controller is a standard method of testing governor type response used internationally and also used in the NEM. However, a significant portion of the NEM's FCAS providers have purely mechanical governors, that cannot receive injected signals. It is conceivable that plant models could be used for this, however availability and accuracy of suitable plant models in the NEM is limited[96]. This is something AEMO is working to improve[97], however, plant model accuracy is also related to ability to test plant. Recorded responses to real events would be illustrative of response speeds under today's conditions, but would require extrapolation to faster or slower frequency nadirs.

The NEM has a wide variety of technologies providing frequency response and participating in the FCAS market. The response at a given time may depend on a variety of factors including unit loading, resource availability (wind resource for wind farms or head level for hydro plant), how the unit controls have been configured including boiler controls, and the amount of stored pressure on large thermal plant. In the NEM, AEMO makes no assumptions about these factors in scheduling reserve, as providers are responsible for providing FCAS in accordance with their selected volumes. Moving to speed factors would either require

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[96] See https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

[97] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-control-work-plan.

AEMO to make some additional assumptions or would require providers to set up their plant to provide a response, within some degree of accuracy, matching the simple modelled response used in scheduling.

How accurately the response of plant can be represented will affect the efficiency of the introduction of speed factors. Where accurate assumptions cannot be made, conservative assumptions would be needed.

6.9.6 Market considerations

Scheduling considerations

The WEM Contingency Reserve makes use of a Dynamic Frequency Contingency Model (DFCM) run in the dispatch process to schedule the correct volumes of service. The system frequency modelling capability in the NEM is an area of continuous improvement[98], which is made more complex by the rate of new connections and other changes on the system, including the development of secondary risks. FCAS is used for system intact operation and the operation of islanded regions and the DFCM would need to facilitate this. The frequency modelling capability in the WEM is more developed. The governor type response from generators not selected in the market is included in the DFCM. Currently in the NEM, frequency control outside of market arrangements is not factored in the volume of services scheduled.

The level of complexity and accuracy required for this type of arrangement for the NEM would require investigation. Where accuracy cannot be achieved consistently, there is a need to make conservative assumptions which may erode some of the theoretical efficiencies of this form of design.

Other market considerations

When implemented at NEM scale, this approach may not present a clear signal for the required speed of response. Potential market entrants would not have a clear specification or target to meet. While faster response is rewarded, predicting how a provider will get selected for this service or what changes are required to get selected more often may not be as transparent as other designs.

The use of time base segmentation has advantages in simplicity and transparency. If a provider meets the service specification, they compete with other providers on price with a one to one relationship.

6.9.7 Security and operability

There may be a need to place limits or additional requirements on FFR type providers that would not apply to slower providers, as outlined in Section 4. Combining all speeds of response into one service may make this more difficult.

6.9.8 Implementation

A change to this form of market would require a fundamental redesign and implantation of key components of the market system and associated process, including:

- Significant design process to develop a conceptual model of this approach in the NEM context, through to implementation level design.
- Changes to scheduling arrangements and constraint design for system intact and separated regions.
- Development of a DFCM suitable for a NEM context, and maintenance of this model in the context of a changing system.
- Changes to the settlements process and procedures.
- Changes to FCAS related components of NEMDE.
- Re-registration of affected FCAS providers and associated testing.

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[98] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-control-work-plan.

6.9.9 Discussion

The scale of the complexity of this type of arrangement and associated costs, when implemented at the NEM scale, are significant. This needs to be evaluated against the potential efficiencies of this type of approach. This form of approach is well suited to the WEM given the acute nature of the frequency containment problem, coupled with a limited number of frequency response providers to meet this challenge.

6.9.10 Locational and temporal incentives

EirGrid employs a range of scalars in its parameterisation of FFR including locational and temporal scalars. The EirGrid FFR service is a contracted service[99] with payments based on available volume of FFR over a trading period, with a number of price scaling factors applied[100], including:

- FFR Performance Scalar – scalar based on the verification of service delivery
- FFR Product Scalar – scalar based on technical parameters of the Dynamic or Static FFR response
- FFR Continuous Scalar – scalar related to the co-delivery of other services.
- FFR Fast Response Scalar – scalar based on speed on the response.
- FFR Locational Scalar – scalar based on the location of the response.
- FFR Temporal Scarcity Scalar – scalar based on system non-synchronous penetration (SNSP) level.

This form of service is different to the existing contingency FCAS arrangements in the NEM. The scaling factors operate under a contract arrangement designed to incentivise speed, time, and location of delivery. These scaling factors are not used to determine a minimum volume of service for frequency containment to be purchased though close to real-time markets setting marginal service prices. Adoption of this type of approach for valuing FFR in the NEM would be conceptually different from extending FCAS delivery to faster response speed.

6.9.11 Evaluation of Option 3

Table 14 Speed scalers

Consideration	Advantages	Disadvantages
System security and operability	Able to maintain system security.	• Security – there may be a need to place limits or additional requirements on FFR type providers that would not apply to slower providers. Combining all speeds of response into one service may make this more complex. • Operability – scheduling correct volume of service more complex than existing arrangements. The complexity of the arrangements may mean there is less flexibility in making future changes.
Implementation		• Complex implementation requiring development of new systems. • Would be more costly and require a longer implementation period than Option 1 or Option 2.
Simplicity and transparency	Would allow for fewer contingency services.	Market outcomes may be less transparent (in the NEM context) and signals for the required response speed may be less clear.
Efficiency	Allows for more granular differentiation in response speed.	Efficiency will be limited by that accuracy of the provider's parameterisation.

[99] See http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Volume-Capped-Protocol-Document-draft-May-2019.pdf.

[100] See https://www.eirgridgroup.com/site-files/library/EirGrid/Ire-DS3-System-Services-Regulated-Arrangements_final.pdf.

6.10 Summary of market implementation options

6.10.1 The number of required contingency FCAS

Reconfiguration of the existing FCAS arrangements to procure FFR while retaining three raise and three lower services (Option 2) is technically possible, and would allow FFR to fulfil its role in ensuring system security. From a market systems implementation perspective, reconfiguration of the existing FCAS is preferable to introducing new services (Option 1) as it would minimise changes. It would also provide a simpler set of services for AEMO to maintain and for providers to manage their participation in.

However, Option 2 would materially impact existing FCAS providers, requiring changes to existing FCAS registrations. Option 1 is also likely to require some changes to existing FCAS registrations, although to a lesser degree and with a lower impact. Market participants should be consulted on combining 6-second and 60-second raise services, particularly if they see this may impact their ability to participate in the re-configured services.

6.10.2 Differential pricing through speed factor parameterisation

Introduction of speed factor parameterisation (Option 3) is not recommended at this time. Speed factor parametrisation of FCAS provision would require significant development in the NEM context. The application of this approach in the NEM may not provide market outcomes as transparent as other approaches, or provide clear signals on the required speed of response.

Abbreviations

Abbreviation	Term in full
AC	Alternating current
ACE	Area Control Error
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
CCGT	Closed-cycle gas turbine
DFCM	Dynamic Frequency Contingency Model
EFCS	Emergency frequency control schemes
ESS	Essential system services
FCAS	Frequency Control Ancillary Services
FOS	Frequency Operating Standard
GPS	Generator Performance Standards
HVDC	High voltage direct current
Hz	Hertz
HZ/s	Hertz per second
IBR	Inverter Based Resources
MASS	Market Ancillary Service Specification
mHZ	Millihertz
MW	Megawatt
MWh	Megawatt hours
MWs	Megawatt seconds
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NOFB	Normal Operating Frequency Band
OCGT	Open-cycle gas turbine
PFR	Primary Frequency Response

Abbreviation	Term in full
Pmax	Maximum power
RIS	Renewable Integration Study
RoCoF	Rate of Change of Frequency
SNSP	System non-synchronous penetration
VPP	Virtual power plant
WEM	Wholesale Electricity Market (WA)

A1. Specific scope items agreed with AEMC

AEMO committed to providing technical advice to the AEMC to inform the development of FFR arrangements for the NEM, with the contents to cover the below high-level scope items.

Technical considerations

- A description of the operational benefits that could be realised through the development and deployment of FFR services in the NEM. *See Section 1.3 Problem* .
- Analysis and commentary to describe how inertia and FFR interact in the power system, including further detail on AEMO's proposed inertia safety net for system intact operation and the impact FFR may have on the settings for the inertia safety net level. *See Section 3.4, Interaction with inertia.*
- Investigation of risks and challenges associated with the integration of FFR, including AEMO's preliminary views on possible strategies for mitigation of these risks through constraints or limits on FFR. *See Section 4, Technical requirements for FFR provision* and *Section 5 Transitional arrangements.*
- An indicative FFR service specification, to provide a basis for investigation of issues related to the integration of FFR. *See Section 2.1, Illustrative technical specification*.
- Preliminary analysis and commentary on the potential to value inertial response as part of the FFR services. *See Section 3.4.1, Valuation of inertia as FFR.*

Input on technical characteristics of market design

- An estimate of current and future FFR capacity availability. See *Section 2, FFR volume requirements*.
- Commentary on the FFR policy options identified in the AEMC's FFR directions paper including consideration of new or revised market ancillary service arrangements with respect to:
  - Operational feasibility.
  - Consideration of consequential impacts on FCAS specifications as a result of the proposed FFR market design options.
  - Impact on provider registration suitability based on the proposed FFR market arrangements (new or revised market ancillary services).
  - The feasibility and applicability of incorporating performance multipliers into the FCAS arrangements to reward FFR.
  - Implementation considerations.

  See Section 6, Market implementation options.
- High level modelling of how the preliminary FFR services would interact with existing FCAS, including the estimated requirement for 6-second raise and lower FCAS for low inertia operation with and without FFR services and the estimated requirement for FFR raise and lower relative to varying levels of system inertia. *See Section 2, FFR volume requirements.*
- AEMO's views on the feasibility of different policy options for integrating FFR in the NEM including:
  - Introducing new market ancillary service classifications for FFR. *See Section 6.4 Option 1: FFR raise and FFR lower added as separate contingency FCAS.*

- Combining and revising the existing FCAS specifications to accommodate an FFR service. *See Section 6.8*
- *Option 2: Introduce FFR by re-specifying existing FCAS* products.
- The use of performance multipliers to value faster active power response within the existing fast services or as part of new FFR services. *See Section 0*
- *Option 3: Differential pricing and scalar* multipliers.
- Interactions between FFR and switched frequency response, including discussion of how switched frequency response is similar to or different from FFR and how this relates to the design of the market ancillary service arrangements. *See Section 2.1, Illustrative technical specification* and *Section 4.1.4, Technical requirements for Switched FFR*.
- Discussion of how FFR contingency response should be coordinated with the mandatory PFR requirement including considerations of frequency response trigger points for FFR, allowance for variable droop, and other factors. *See Section 3.3 Interaction with PFR requirements.*

Implementation and staging

- AEMO's views on the process for the implementation of FFR arrangements in the NEM. *See Section 5, Transitional arrangements.*
- AEMO's views on the challenges associated with implementing FFR arrangements and how transitional arrangements could help manage the associated risks. *See Section 5 Transitional arrangements.*
- Estimated cost for implementation of new FFR ancillary service market arrangements. *Implementation considerations are detailed under Section 6, Market implementation options. AEMO is assessing how indicative costings can be provided, noting the broad range of options that need to be refined for detailed costings.*

A2. FCAS 6-second and 60-second service segmentation

This Appendix is an addendum to Section 6.8.8 that analysed the use of 6-second and 60-second service segmentation using FCAS registration data. The below analysis uses FCAS availability data to compare the volume of R6 available to the volume of R60 available, as indicated by the FCAS availability measure from historical market data.

Availability market data of R6 and R60 providers

Figure 23 directly compares the R60 and R6 availability data[101] (by technology type) when both services are enabled. For every 30 minute period of the year from October 2019 to October 2020, an R60/R6 ratio is calculated based on indicated availability for that period. Providers must offer some value of R6 and R60 to be included. The values shown are average of the providers in each technology type.

All technology types except switched FCAS have a noticeable concentration in R60/R6 equal to one, which is when the availability of both services is roughly the same. This suggests that these providers have available roughly equal proportions of R6 and R60. Batteries and VPPs, subcritical steam providers, and gas turbines most frequently have available the same response for R60 and R6, at about 60% of the time.

Batteries, VPPs, and switched load providers show greater numbers of instances with a ratio of less than one, indicating a greater volume of R6. As with the registration data, for very fast providers the higher R6 value is likely due to having a higher registration value than instantaneous 6-second response, rather than an R6 response that is not sustained into the R60 timeframe.

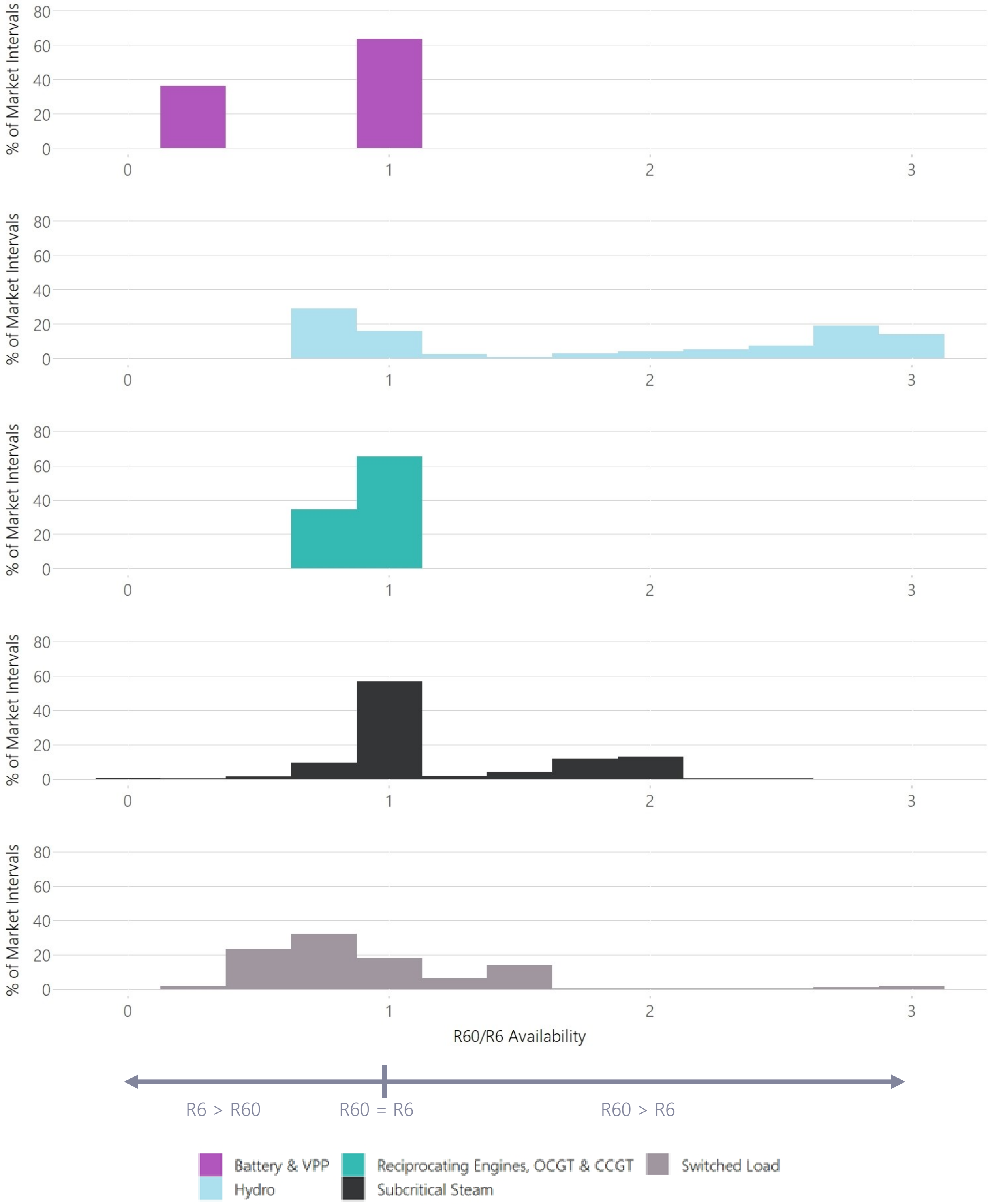
Hydro showed a spread of values with ratios greater than one, suggesting slower responses that are not fully achieved in the R6 timeframe. R60/6 values less than one primarily came from two providers.

Subcritical steam showed some instances with R60/R6 values being less than one. The instances of values less than one came from two providers.

The gas turbine group also showed some instances with R60/R6 ratio being less than one. The instances of values less than one came from one OCGT.

[101] See https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2017/FCAS-Model-in-NEMDE.pdf.

Figure 23 R60/R6 ratio by technology type



6.10.3 Subcritical steam plant

It is assumed that the initial market segmentation between the 6-second and 60-second services was introduced based on the capabilities of the predominate FCAS providers at the time of market creation. Subcritical steam plant historically provided the majority of FCAS and still provide a large proportion of all

FCAS. Conventional steam turbines can provide rapid responses to frequency using stored pressure in their boilers. While this response can be very rapid it may not be readily sustained. This response can theoretically be provided from some plant when operating at their maximum continuous output level.

The FCAS market segmentation of the subcritical stem plant registration and market availability data, at different loading levels, has been used to determine if there is high usage of the R6 service to value a response that is not sustained. The R6 and R60 registered capacities are compared for all currently registered subcritical steam plants in the NEM at varying power outputs in Table 15.

Table 15 Registered R60 and R6 capacities of subcritical steam plants at different power outputs

Metric of comparison	R60	R6	R60/R6 ratio
Total FCAS_MW at 50% of power output	2,340	1,720	1.36
Total FCAS_MW at 90% of power output	2,020	1,480	1.36
Total FCAS_MW at 95% of power output	1,560	1,120	1.40
Total FCAS_MW at 98% of power output	1,100	790	1.39

Table 15 highlights that both the R60 and R6 registered capacities of subcritical steam plants decrease as the plant output increases, because there is increasingly limited headroom available for the plant to increase power output. The average registered R60 capacity for subcritical steam plants is about 40% larger than their registered R6 capacity. Additionally, the registered capacity ratio of R60/R6 remains relatively constant at varying power plant outputs. The registration data does not suggest a high level of usage of R6 service to value a response that is not sustained.

Figure 24 compares R60 and R6 FCAS market availability data for subcritical steam plants, across a range of loading levels. While there is some increase in R60/R6 ratios less than one at increased loadings, there is not a large difference between the R60/R6 ratio between loading levels, with a consistent proportion (~60%) having a R60/R6 ratio of one.

Figure 24 R60/R6 ratio for subcritical steam plant by loading