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Response to Fast frequency response market ancillary service draft rule determination

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3 June 2021

Ben Hiron

Senior Adviser

Australian Energy Market Commission

Lodged electronically

Dear Mr Hiron,

Re: Fast frequency response market ancillary service draft rule determination

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission in response to the Australian Energy Market Commission's (AEMC) draft rule determination on a Fast frequency response market ancillary service.

About us

The UNSW Collaboration on Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from a range of faculties, working alongside a number of Australian and international partners. CEEM's research focuses on the challenges and opportunities of clean energy transition within market-oriented electricity industries. Effective and efficient renewable energy integration is key to achieving such energy transition and CEEM researchers have been exploring the opportunities and challenges of market design and policy frameworks for renewable generation for the past two decades. More details of this work can be found at the Collaboration website. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please contact Abhijith (Abi) Prakash regarding this submission (abi.prakash@unsw.edu.au), and Associate Professor Iain MacGill, Joint Director of the Collaboration (i.macgill@unsw.edu.au) and/or Dr Anna Bruce, CEEM's Engineering Research Coordinator (a.bruce@unsw.edu.au) for other CEEM matters.

Our submission

We welcome the release of AEMO's *Fast Frequency Response Implementation Options* report and the Commission's draft determination. Broadly speaking, we feel that the analysis presented by AEMO in the *Implementation Options* report has addressed some of our initial concerns around the effectiveness and efficiency of a contingency fast frequency response (FFR) market ancillary service, as detailed in our earlier submission[1]. In particular, we note that AEMO's frequency response modelling suggested that during low-inertia system intact operation, frequency containment could be achieved through FFR procurement replacing large amounts of synchronous inertia and/or greater volumes of raise fast contingency FCAS (R6)[2]. Furthermore, whilst this modelling only accounted for system intact inertia levels (i.e. greater than 40,000 MW·s), we expect that procuring FFR at lower operational levels will provide an even greater benefit in terms of system costs. In the short to mid-term, these lower operational inertia levels may occur when regions are islanded, or may be relevant to meeting minimum regional inertia requirements. In the longer term, the ability to procure FFR will likely assist AEMO in ensuring that frequency stability can be achieved in a low-inertia and low carbon NEM. As such, we are generally supportive of this rule change.

[1] Abhiijith Prakash, Iain Macgill, and Anna Bruce, "Response to Frequency Control Rule Changes Directions Paper," 2021.

[2] Australian Energy Market Operator, "Fast Frequency Response Implementation Options," 2021, p27–28.

However, as raised by AEMO in their *Implementations Report* and acknowledged by the AEMC in the draft determination[3], we are of the view that there may initially be unnecessary risks and uncertainty for participants who might offer capacity in the new FFR contingency FCAS markets. Under the transitional and implementation arrangements outlined in the draft rule determination, there is a possibility that in the years preceding market implementation and possibly even for a period following market implementation, market participants who invest in FFR capability or resources that are FFR-capable may be faced with a changing service specification, regional limits and dispatch constraints that enforce more local limits on FFR provision. Without interim or transitional arrangements that enable AEMO to obtain operational experience with FFR (e.g. structured procurement of FFR across areas of the network) and that provide information about FFR provision viability to market participants, this uncertainty may lead to inefficient investment in power system resources capable of fast frequency response.

Furthermore, we would like to take this opportunity to discuss possible future directions for frequency control in the NEM. We reiterate the need for upcoming reviews of the Frequency Operating Standard (FOS) and the Market Ancillary Service Specification (MASS) and, more generally, the need for reviewing existing aspects of FCAS markets such as the methodology for dynamically determining FCAS procurement volumes. Such reviews should also ideally take a forward-looking approach to frequency stability, which might include defining additional system requirements to ensure the power system and its resources can be operated in a stable manner without tying these requirements to any particular solution[4] (e.g. "What is an acceptable system RoCoF? Will this change?" rather than "How much inertia do we need?"). As these requirements and the ability to address them will change over time during electricity industry transition, it seems reasonable that should be regular and systematic reviews of the FOS, MASS and FCAS procurement volumes. This could assist in delivering a more proactive regulatory framework for frequency control in the NEM.

If these regular reviews are undertaken, they should be informed by an ongoing assessment of NEM frequency control performance and the findings from operational trials of emerging capabilities (e.g. provision of inertial response from grid-forming inverters). We encourage the AEMC and AEMO to outline what *ex post* FCAS validation is currently in place, how such processes could be improved and how regulatory flexibility could better enable AEMO to contract with providers for small-scale operational trials that explore new capabilities beyond ARENA demonstration programs[5].

We would of course be very happy and interested to discuss these comments further with the AEMC if that is of interest to you and your colleagues. All the best for this challenging but extremely important work, and sincere regards

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[3] Australian Energy Market Commission, "Fast Frequency Response Market Ancillary Service, Draft Rule Determination," 2021, p58.

[4] We note that this is the approach being taken by the Global Power System Consortium (G-PST) Working Group on System Needs and Services (presentation by Timothy Green of Imperial College London – "Is Grid Forming Enough? What Do Electricity Grids Need From IBR?"). Publication of statement forthcoming.

[5] Regulatory flexibility for AEMO and TNSPs was discussed in Energy Security Board, "Post 2025 Market Design Consultation Paper," 2020, p73. However, it was not included in the subsequent Options papers.

Need for transitional measures

As outlined in the *Implementation Options* report, AEMO is concerned about the secondary effects of Fast Active Power Response (FAPR) that would be delivered by very fast contingency FCAS providers. The first of these effects is the potential for FAPR to increase angular separation between weakly interconnected areas of the network (e.g. NEM regions) and increase the risk of regional separation, particularly where interconnectors are limited by transient stability[6]. Furthermore, greater angular separation could reduce the synchronising torque on synchronous machines and thereby have a negative effect on the synchronous machine's transient stability, should they be subject to further disturbances[7]. We expect such issues may be partially addressed through the regional FFR requirements and delivery caps proposed by AEMO.

The second of these effects is related to local voltage management and system integrity protection systems (SIPS). Researchers from the University of Melbourne[8] and the Electric Power Research Institute[9] have been studying FAPR and phase-locked loop stability of IBR in weak parts of the network and have concluded that effective FFR may require reactive power provision (voltage control) to maintain stable IBR operation. While these researchers have developed control strategies that have enabled IBR to provide this reactive power support, this provision may reduce the FAPR available given inverter rating limits. We expect AEMO will use FFR dispatch constraints to restrict, or altogether constrain-off, FFR in such weak parts of the network. Similarly, dispatch constraints may be used where FFR may affect system integrity protection systems.

As such, without transitional measures that enable AEMO to test local dispatch constraints, regional requirements and the FFR service specification, we are concerned that market participants that are considering FFR provision may face the following risks in the three years preceding market implementation, and potentially even for a period after market implementation:

- The very fast contingency FCAS service specification may change and AEMO has also flagged that they may apply limits to the proportion of FFR obtained from switched FFR providers[10]. The former could result in additional costs for software/firmware changes in the inverter control settings, and the latter is a large uncertainty for market participants who are currently offering or planning to offer switched FCAS in the NEM.
- If delivery caps, regional requirements and potential dispatch constraints are not tested using existing assets, there may be uncertainty for investors with regards to how much FFR is required and where.

These risks and uncertainty could lead to participants developing IBR projects with the intention to participate in FFR markets but then being "constrained-off" FFR in dispatch, restricted in their ability to participate in the event of controller-type or regional requirements, and/or needing to re-register should specifications change. This could lead to some degree of inefficient investment (e.g. installation of a new battery energy storage system or upgrade of existing IBR in a part of the network where FAPR is undesirable), thereby affecting participant confidence in their return on investment. These risks and

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[6] National Grid ESO, "The Enhanced Frequency Control Capability (EFCC) Project Closing down Report," 2019, p14, "Fast Frequency Response Implementation Options," p33; Australian Energy Market Operator, "Interconnector Capabilities for the National Electricity Market," 2017.

[7] Ivan M. Dudurych, "The Impact of Renewables on Operational Security," *IEEE Power and Energy Magazine*, February (2021): p37–45.

[8] Mehdi Ghazavidozein, Oriol Gomis-Bellmunt, and Pierluigi Mancarella, "Simultaneous Provision of Dynamic Active and Reactive Power Response from Utility-Scale Battery Energy Storage Systems in Weak Grids," *IEEE Transactions on Power Systems* 8950, no. c (2021): 1–1, https://doi.org/10.1109/TPWRS.2021.3076218.

[9] Electric Power Research Institute, "Grid Inertia: Current Perceptions, Future Trends," 2021.

[10] Australian Energy Market Operator, "Fast Frequency Response Implementation Options," p37.

uncertainty could also affect the availability of FFR capability in the NEM as we transition to instantaneous VRE penetrations of 75-100% in what may be as little as the next four years[11].

As outlined by AEMO[12], out-of-market structured procurement mechanisms are employed widely in Europe and could assist in improving market information to potential providers so long as the procurement process is transparent and key findings, including potential regional and locational constraints and provision caps, are made publicly available. We note that such market information is important for efficient investment decisions, particularly for the large number of battery energy storage systems that have been proposed in the NEM (Figure 1).

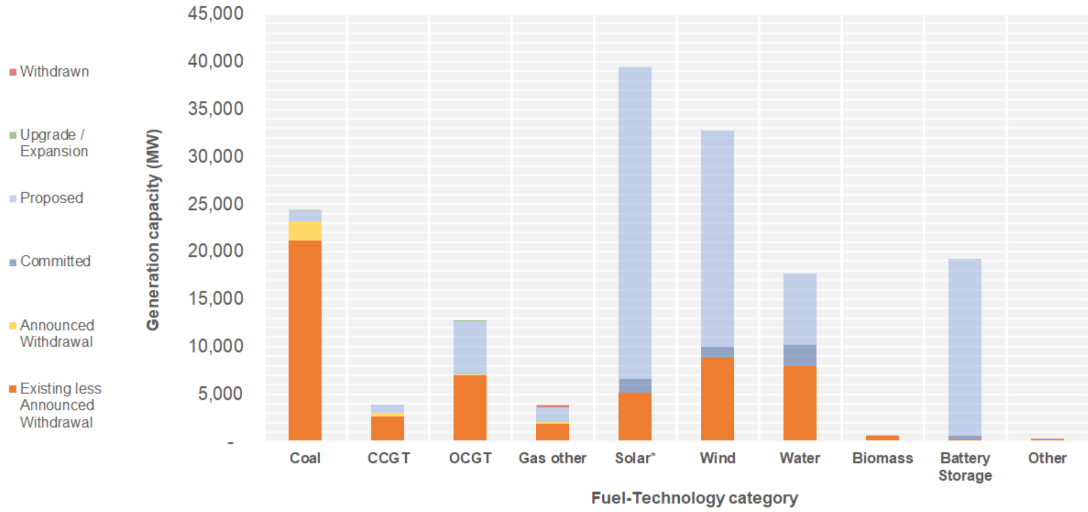

Figure 1: AEMO NEM Generation Information over the next 10 years (as of May 2021). Source: [NEM Generation Information May 2021.]

Future directions for frequency control

In our view, frequency control requirements for the NEM are defined by:

1. The capabilities of frequency control resources and frequency-related limits that ensure safe and stable operation of power system equipment (e.g. stability of phase-locked loops or relays that trip equipment to prevent equipment damage due to vibrations or pole-slipping).
2. More "passive" and potentially path-dependent characteristics of the power system, such as the degree of regional interconnection.

During electricity industry transition, it is our view that the former (capabilities and limits) will change at a pace far greater than that of the latter. While this alone should warrant ongoing and systematic review of frequency control in the NEM, we note that more "passive" power system characteristics may challenge existing assumptions or limit our ability to leverage new capabilities. A pertinent example is that while frequency control has historically been viewed as a "global" NEM system service, weak interconnection between regions and system strength issues in certain parts of the network are increasingly introducing a "local" aspect to frequency control.

[11] Australian Energy Market Operator, "Renewable Integration Study : Stage 1 Report," 2020.

[12] Australian Energy Market Operator, "Fast Frequency Response Implementation Options," p39.

Furthermore, as the valuation of additional essential system services are being considered, the interaction between frequency control and these services needs to be further explored. For example:

1. How should intra-dispatch FCAS interact with a potential operating reserves service, which would be required to respond after one or more dispatch intervals? Should FCAS "hand over" to operating reserves? Or will they function together as a part of a frequency control hierarchy?

3. As system services become increasingly disaggregated, how should they be prioritised? For example, if a battery energy storage system is in a weak part of the network, should it provide reactive power support at the cost of FFR provision, and if so, should it be remunerated for any opportunity-cost? Or should this be handled by discrete service provider, such as a system strength providers procured by a TNSP?

These issues and questions will likely need to be addressed by an iterative regulatory process driven by operational experience. While we see rule change processes playing a major role in this process, we still see a need for regulatory flexibility that would enable AEMO and the AEMC to make smaller "tweaks" and take on a more proactive role as the NEM continues to transition. An example of such flexibility could be to conduct regular reviews of the Market Ancillary Service Specification (MASS), the Frequency Operating Standard (FOS) and the methodology for dynamically determining FCAS volumes[13]. If such regular reviews were undertaken, they should ideally be informed by:

- Frequency control performance monitoring, which should go beyond statistical reporting on NEM frequency and assess unit contributions and technology capabilities. We would encourage AEMO and the AEMC to outline what *ex post* FCAS validation is currently in place and how such processes could be streamlined or improved; and

- Experience from operational trials. These trials could involve a structured procurement process run by AEMO that acquires small volumes of a service from resources that offer a capability that has yet to be demonstrated in the bulk power system. Such trials could neatly dovetail with ARENA-funded trials and demonstration programs, which, in the case of utility-scale resources, are often site-specific.

A proactive regulatory framework would also focus on system requirements rather than particular solutions. For example, a NEM-wide RoCoF limit could be established and met through a variety of solutions, such as physical inertia, virtual inertia from grid-forming inverters or even FFR provided by grid-following IBRs[14]. As IBR penetrations increase and enable system services to become increasingly disaggregated[15], it is conceivable that a RoCoF limit would enable physical inertia safety nets and regional requirements to be met, or altogether replaced by a performance-based RoCoF service that could be provided by a combination of technologies and control topologies. In this way, designing system service requirements around needs rather than specific solutions can provide flexibility to operators with respect to which (combination of) solutions can be deployed.

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[13] We note that the biennial Power System Frequency Risk Review (soon to be General Power System Risk Review) accounts for non-credible contingencies. We are suggesting a broader review of frequency control arrangements in the NEM.

[14] Lasantha Meegahapola et al., "Power System Stability in the Transition to a Low Carbon Grid: A Techno-economic Perspective on Challenges and Opportunities," *WIREs Energy and Environment*, no. February (April 5, 2021): 1–27, https://doi.org/10.1002/wene.399; Yashen Lin et al., "Research Roadmap on Grid-Forming Inverters," *NREL*, 2020.

[15] We note, however, that certain requirements will remain coupled so long as synchronous machines are still connected to the power system. An example is how inertial response/RoCoF mitigation may improve transient stability.

Acknowledgements

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The views presented in this submission are solely those of the authors, and don't necessarily represent the views of the Digital Grid Futures Institute or, more generally, UNSW Sydney.