AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

16 August 2019

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Mr John Pierce
Chair
Australian Energy Market Commission
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Dear Mr Pierce

Mandatory Primary Frequency Response Rule Change Proposal

The Australian Energy Market Operator (AEMO) submits the attached Rule change proposal to support the provision of a secure and reliable electricity supply.

Under system normal operating conditions, the NEM mainland frequency standard requires system frequency should not exceed the normal operating frequency band for more than five minutes on any occasion and not for more than 1% of the time over any 30 day period. The normal operating frequency band is currently set at ±0.150 Hz away from the nominal frequency of 50 Hz.

For the period between January 2019 and April 2019, the mainland frequency dropped below this standard. This is a symptom of the lack of effective control of frequency under normal operating conditions, which cannot be achieved without assistance from generation plant capable of responding to frequency changes in the power system. The decline in the primary frequency response (**PFR**) of generating systems has resulted in this lack of effective frequency control within the normal operating frequency band, which has reduced both the resilience, and the predictability, of the power system's response to major disturbances.

The potential consequences of the current frequency conditions are serious and becoming steadily greater as more variable renewable and inverter-connected generation comes into the power system. To mitigate these risks, there is an immediate need for significantly increased PFR from NEM generation to reverse the decline in frequency performance.

Informed by advice from an international expert in power system dynamics and control, AEMO is proposing a Rule to require all capable scheduled and semi-scheduled generating units to provide PFR once frequency is outside a narrow specified frequency band of ±0.015 Hz. This would align the NEM with frequency control practice in other comparable power systems.

A near-universal PFR obligation provides the most effective means of regaining control of frequency within the normal operating frequency band and re-establishing prudent electricity industry practice.

AEMO believes this proposal advances the National Electricity Objective and is in the long term interest of consumers. We note that mandatory provision of PFR will not replace the need to procure market ancillary services.

AEMO also subscribes to the principle of compensation for services. This proposal where required incorporates one-off compensation for relevant Generators for any material capital costs associated with equipment changes. The issue of whether or not on-going fair compensation is applicable is complex, and worthy of consideration in the context of ancillary service markets as a whole.

Mandatory provision of PFR shouldn't be regarded as a 'free' service, as all scheduled and semi-scheduled electricity providers would be expected to price the cost of compliance into their market offers. However, given the seriousness of the deterioration in frequency performance, AEMO is mindful that debate on the merits of explicit on-going fair compensation ought not be a hinderance to the immediate implementation of this Rule.

AEMO requests that this rule change proposal is progressed as quickly as possible. Frequency control is a vital aspect of power system operation that directly affects the ongoing operation of connected equipment and consequently the security, reliability and cost of electricity supply to consumers. AEMO's reduced ability to control power system frequency is materially out of step with established international standards of grid operation. AEMO considers it imperative for system security that a regulatory framework facilitating effective frequency control is implemented at the earliest opportunity.

AEMO looks forward to working with the AEMC as it considers this proposal. Please do not hesitate to contact Kevin Ly, Group Manager Regulation at Kevin.Ly@aemo.com.au should you wish to discuss any aspect of this proposal.

Yours sincerely

Peter Geers
Chief Strategy and Markets Officer

Attachments:

1. Rule Change Proposal – Mandatory Frequency Response
2. Notes on Frequency Control for the Australian Energy Market Operator, Report by J. Undrill, 5 August 2019
3. Primary Frequency Response Requirements (PFRR)

ELECTRICITY RULE CHANGE PROPOSAL

MANDATORY PRIMARY FREQUENCY RESPONSE

August 2019

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NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA WESTERN AUSTRALIA

CONTENTS

1. SUMMARY

There has been a decline in the primary frequency response (**PFR**) provided by generation in the NEM. This has resulted in a lack of effective control of frequency in the NEM under normal operating conditions, and has reduced both the resilience, and the predictability, of the power system's response to major disturbances.

The potential consequences of the current frequency conditions are serious, and becoming steadily greater as more inverter-connected generation comes into the power system. To mitigate these risks, there is an immediate need for significantly increased PFR from NEM generation, sufficient to reverse the decline in frequency performance.

AEMO initially considered a rule that would require technically capable generation to provide PFR once local frequency reached the limits of the normal operating frequency band (**NOFB**), specified for the NEM (currently set at ±0.150 Hz away from the nominal frequency of 50 Hz). While this could be expected to improve the resilience of the power system to major disturbances, it has become clear that the lack of effective frequency control within the NOFB remains a core issue.

Informed by advice from an international expert in power system dynamics and control[1], AEMO is proposing a rule that requires all capable scheduled and semi-scheduled generating units to provide PFR once frequency is outside a narrow specified frequency band, aligning the NEM with frequency control practice in other comparable power systems. The proposed band is ±0.015 Hz.

A near-universal PFR obligation provides the most effective means of regaining control of frequency within the NOFB, and re-establishing prudent electricity industry practice in this respect. AEMO remains committed to working closely with the AEMC and industry on options for incentivising PFR in the future, as contemplated in the AEMC's Frequency Control Frameworks Review. This proposal establishes and proposes a means to address the urgent need for PFR, while not detracting from the development of efficient alternative or complementary long term market solutions. AEMO notes that mandatory provision of PFR will not replace the need to procure market ancillary services. Nor should it be regarded as a 'free' service, as all electricity providers would be expected to price the cost of compliance into their market offers.

AEMO requests that this rule change proposal is progressed as quickly as possible. Frequency control is a vital aspect of power system operation that directly affects the ongoing operation of connected equipment and consequently the security, reliability and cost of electricity supply to consumers. AEMO's reduced ability to control power system frequency is materially out of step with established international standards of grid operation. AEMO considers it imperative for system security that a regulatory framework facilitating effective frequency control is implemented at the earliest opportunity.

2. RELEVANT BACKGROUND

2.1 What is primary frequency response?

PFR is the first stage of frequency control in a power system. It is the response of generating systems and loads to arrest and correct locally detected changes in frequency by changing their active power output or consumption. PFR is automatic; it is not driven by a centralised system of control and begins immediately after a frequency change beyond a specified level is detected.

[1] The full report from AEMO's consultant is included as an attachment to this rule change proposal.

Stable control of frequency relies on PFR, making PFR essential for power system security. Accurate knowledge of available PFR is required for power system modelling and event analysis, and it is critical following power system disturbances and during power system restoration.

2.2 Frequency control in the NEM

When the NEM was first conceived the power system was dominated by large synchronous generators, the majority of which provided PFR continuously because it was mandatory for most plant[2]. This resulted in its widespread provision across the NEM. PFR was required outside a frequency deadband specified at no larger than ±0.050 Hz, which was half the NOFB at the time.

In 2001, real-time ancillary services markets for frequency control services were established. Eight new services were created, commonly referred to as frequency control ancillary services (**FCAS**) – six "Contingency FCAS", and two "Regulation FCAS". These market ancillary services are specified in clause 3.11.2(a) of the current National Electricity Rules (**NER**). AEMO is required by clause 3.11.2(b) to publish a market ancillary service specification (**MASS**)[3], in which each FCAS is described and performance parameters and other requirements are stipulated.

Although referred to as ancillary services, these are, in fact, better described as frequency control reserves. The new market arrangements were primarily intended to ensure that minimum levels of MW reserves would be set aside to be used for frequency control purposes, and that these reserves were procured in the most economic manner every 5 minutes. A critical choice made at the establishment of these markets was that ongoing provision of PFR would no longer be mandatory. It was instead only required from generation that voluntarily participated in the new markets for the provision of Contingency FCAS, and even then, only once frequency was outside the NOFB.

As part of these reforms, the NOFB was also widened by the Reliability Panel[4] from the previous level of ±0.100 Hz to ±0.150 Hz to reduce the cost of Regulation FCAS, resulting in the acceptance of greater variation in frequency under normal operating conditions.

There was no longer an ongoing requirement, or direct incentive, for any Generator to provide PFR within this widened NOFB. Instead, centralised secondary control via Automatic Generation Control (**AGC**) of MW reserves procured through the Regulation FCAS markets became the only explicit mechanism in the NER for control of frequency within the NOFB under normal operating conditions.

These new FCAS markets initially led to a significant decline in the costs of procuring frequency control reserves. Even though the provision of PFR was no longer mandatory, most Generators did not immediately change their control systems to reduce provision of PFR, and for some years there was little change in the power system's actual frequency performance, particularly under normal operating conditions.

More recently, however, power system frequency performance has declined dramatically. For periods through 2018 and 2019, the minimum standards specified in the Frequency Operating Standard (**FOS**) have not been achieved. This decline, in part, led to the AEMC's Frequency Control Frameworks Review.

2.3 Role of primary frequency response in frequency control

In a conventional power system, frequency control consists of three layered components:

2 Clause 4.4.2(b) of version 1 of the NER. It is noted that the National Electricity Code, which preceded the NER, also contained clause S5.2.6.4, which specified provision of PFR outside a narrow deadband.

3 Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Market-Ancillary-Service-Specification-V50--effective-30-July-2017.pdf

4 Reliability Panel, September 2001, Frequency operating standards – Determination, p.9.

1. Inertial response (instantaneous)
2. Primary frequency response (within 10 seconds and up to 30 seconds)
3. Secondary frequency control (within 30 seconds and up to 30 minutes)

2.3.1 Inertial response

The inertial response of a power system assists in limiting the rate of change in frequency during large disturbances so that control systems have time to respond.

Inertial response is provided through the acceleration or deceleration of rotating synchronous machines in response to frequency changes. It is an inherent physical characteristic of rotating machines. The level of inertia in the power system will determine how fast power system frequency will change in the first few seconds of a frequency disturbance.

AEMO recently conducted an analysis of the NEM's inertia requirements and found a shortfall in SA, which ElectraNet, the transmission network service provider (**TNSP**) in SA, must address[5].

2.3.2 Primary frequency response

As described in Section 2.1, PFR is:

- A response to locally-measured frequency and, hence, not subject to centralised control, communications delays and time synchronisation issues.
- Fast-acting; response to frequency change typically starts immediately.
- An automatic response to adjust generation output to arrest and stabilise (but not necessarily restore) frequency, typically in proportion to the measured frequency deviation.

Contingency FCAS when delivered from a proportional controller is a form of PFR, albeit with a very wide zone of insensitivity not seen in other comparable power systems.

Historically in the NEM, only synchronous generating systems provided PFR. It is now also being provided by wind, batteries and PV generation. As these technologies will form an increasingly large proportion of the supply mix in the future, it is important that any PFR arrangements consider the capabilities and performance of these newer technologies adequately.

2.3.3 Secondary frequency control

Secondary frequency control is a centralised correction of generator setpoints, in response to measured changes in power system frequency and time error, relying on communications, calculations and feedback.

Regulation FCAS is a part of the NEM secondary frequency control arrangements. It is:

- Dependent on a centralised single frequency reference, with the responses centrally determined by AEMO's AGC system.
- Complementary to PFR, allowing generation providing PFR to return to set-point and thus be ready to provide further PFR, if required.
- Slow-acting, primarily because of centralised control and latency in communications through AGC. As AGC is managed via SCADA and includes a range of deliberate rate limits and compensation functions, response delays of tens of seconds are typical, though slightly faster responses can be achieved in some cases. Furthermore, responses cannot be synchronised across different units.

[5] See section 3.2 of AEMO's National Transmission Network Development Plan - December 2018. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf

- Not necessarily continuous following an islanding event, as AGC must be reconfigured for the separate frequency islands before correct control instructions can be issued.

2.4 Frequency Control Frameworks Review

The AEMC published its Final Report: Frequency Control Frameworks Review on 26 July 2018 (**AEMC Final Report**), which dealt with, among other things, PFR in the NEM, particularly under normal operating conditions.

The AEMC accepted that there has been a material deterioration of frequency performance in the NEM under normal operating conditions[6]. To address this, the AEMC made, amongst others, the following recommendation:

> RECOMMENDATION 1: ARRANGEMENTS FOR THE PROVISION OF PRIMARY REGULATING SERVICES
>
> In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.
>
> In order to develop such a mechanism, the Commission supports AEMO's trialling of changes to generator governor settings in Tasmania and the mainland, and associated technical investigations by AEMO, which are expected to be complete by December 2018.
>
> The Commission recommends that the results of these trials and investigations be used to develop an explicit mechanism to incentivise the provision of a sufficient quantity of primary regulating services to support good frequency performance during normal operation. This will be important to securing sufficient volume of this service in the future for the evolving power system.

The AEMC Final Report reflected AEMO's advice at the time that there was no immediate need to implement regulatory change to address the deterioration pending the results of investigations to understand the issue[7], however, it also noted that the ongoing short-term work program would enable AEMO to assess:

> ... whether there is a need for an interim measure to be put in place before a longer term mechanism for the procurement of a primary regulating response comes into effect. Notwithstanding practical viability, potential interim measures may include:
>
> - those that might not require regulatory change (e.g. AEMO negotiating with generators or issuing directions
> - those that would likely require regulatory change (e.g. mandatory provision of primary frequency control, a new contracting arrangement or valuing positive contribution factors through the causer pays procedure).[8]

2.4.1 AEMO actions subsequent to Final Report

The AEMC proposed a staged work program to facilitate the formulation of solutions to the problem of deteriorating frequency response in the NEM, including actions to be completed by AEMO to assist the AEMC in its deliberations[9]. AEMO was to monitor and report to the AEMC on a quarterly basis on frequency outcomes following tasks completed in the short-term and medium-term. Table 1 details the status of actions undertaken by AEMO to date.

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6 AEMC Final Report, page 68.
7 AEMC Final Report, pages iii, 37, 58 & 85.
8 AEMC Final Report, page 38
9 AEMC Final Report, Table 4.1

Table 1 Update on AEMO's actions

Task	Completion	Comments
Survey of generator frequency control settings	April 2018	Survey completed. AEMO is now aware that there is a wide and complex array of control settings in use.
Trial of (increased) primary frequency control in Tasmania	May 2018	Narrowing the frequency response settings on selected Hydro Tasmania generating units resulted in significant and immediate improvement in the control of frequency in TAS under normal operating conditions. The role of AGC settings was less significant than the generator governor settings on power system frequency performance under test conditions.
Publish a revised causer pays procedure	Nov 2018	A change was made to allow causer pays calculations to ignore 4-second samples where the frequency indicator and system frequency in a synchronous area are mismatched.
AGC tuning	Ongoing	A trial of increased Regulation FCAS volumes initially ran from October to December 2018. Adjustments to AGC tuning were made late 2018, and AEMO has commissioned a further review in mid-2019, which may result in further adjustments.
Investigate the need to increase the quantity of Regulation FCAS on a static or dynamic basis, and doing so if necessary	Ongoing	The quantity of both types of Regulation FCAS for the mainland was increased on a static basis by 50 MW in March 2019 with further increases of 20 MW each in April 2019 and May 2019.[10] The need for further increases is being evaluated regularly, based on the observed change in power system frequency performance under normal operating conditions.
Trial of (increased) primary frequency control in the mainland	Ongoing	The event on 25 August 2018 superseded the immediate plan for a trial in the mainland along similar lines to that undertaken in TAS earlier in 2018. Another rule proposed by AEMO could facilitate such a trial in the future.[11]
Monitor and report quarterly on frequency outcomes	Ongoing	AEMO has published three reports since the AEMC Final Report.[12] The AEMC has also recently made a rule to place formal obligations on AEMO for reporting on frequency performance and related measures[13].
Coordinate proposed changes to generator governor settings	Ongoing	In November 2018, AEMO rejected a request from a Generator to widen its plant's governor deadband settings. AEMO will respond similarly to other requests until more permanent measures are in place to halt the degradation in PFR. AEMO has clarified the deadband settings required from FCAS providers and will continue this through revision of the MASS in due course.
AEMO to report on the outcomes of these actions as results become available, through its Ancillary Services Technical Advisory Group, Frequency Control Working Group or published reports (or both).	Ongoing	The Frequency Control Working Group held stakeholder meetings on 26 November 2018 and 17 December 2018 and during February – April 2019 on potential rule changes.
Independent review of NEM frequency control arrangements.		AEMO engaged an international expert to investigate and make recommendations on changes to frequency control arrangements. The consultant's report is provided with this rule change proposal.

[10] Fact sheet and updates published on AEMO's website at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

[11] AEMO's other rule change proposal is entitled: Electricity Rule Change Proposal - Removal of Disincentives to the Provision of Primary Frequency Response submitted contemporaneously with this one.

[12] At as 30 April 2019. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

[13] https://www.aemc.gov.au/rule-changes/monitoring-and-reporting-frequency-control-framework

AEMO was of the view during the AEMC's Frequency Control Frameworks Review consultation that while changes to the NEM's frequency control arrangement were needed to address the ongoing deterioration in frequency performance, time was still available for further investigations to understand the issues and to ensure that any proffered solutions would deliver the required power system behaviour.

The power system incident on 25 August 2018 was significant in confirming an urgent need for regulatory changes to arrest the ongoing decline in the frequency performance in the NEM, in particular the resilience of the NEM to similar major disturbances.

Leading up to and following completion of the detailed 25 August event report in early 2019, AEMO worked on identifying appropriate regulatory changes. AEMO undertook a range of consultation and engagement over this period with industry participants, both via forums such as the Ancillary Services Technical Advisory Group (ASTAG), and individual meetings with stakeholders.

Over June and July 2019, discussions with international power system dynamics and control expert Dr John Undrill assisted AEMO to finalise the exact nature of changes required to existing NEM frequency control arrangements, in particular in relation to the level of frequency deadband outside of which these requirements should apply.

This work has led ultimately to development of a proposal for a basic mandatory requirement for all capable generation to provide a level of PFR, where it is capable of safely and stably doing so.

2.5 Incident on 25 August 2018

On 25 August 2018, a lightning strike on a transmission tower structure supporting the two 330 kV QLD–NSW interconnector (**QNI**) lines caused simultaneous faults on single phases of both circuits of QNI. The QLD and NSW power systems ultimately lost synchronism as a result of these faults, islanding the QLD region. The full sequence of events and analysis is set out in AEMO's final incident report published on 10 January 2019[14] (**AEMO Incident Report**).

Because 870 MW of electricity was flowing from QLD to NSW at the time, QLD experienced an immediate supply surplus, resulting in a rise in frequency. The remainder of the NEM experienced a supply deficit, resulting in a reduction in frequency. In response to this reduction:

- The frequency controller on the Basslink interconnector immediately increased flow from TAS to VIC creating a supply deficit in TAS, which caused the disconnection of 81 MW of contracted interruptible load under the automatic under-frequency load shedding scheme AUFLS2 to rebalance the TAS power system.
- The SA–VIC interconnector at Heywood experienced changes in power system conditions that triggered the Emergency APD Portland Tripping scheme, which separated the SA region from VIC at Heywood. At the time of separation, SA was exporting electricity to VIC, which resulted in a supply surplus in SA, causing frequency to rise. In the remaining VIC/NSW island, the supply deficit was increased, and frequency continued to fall until under-frequency load shedding (**UFLS**) was triggered.

The responses of each type of generation during this event are summarised in Table 2:

Table 2 Responses from all measured Generation during 25 August 2018 Event

Generation	Percentage of Total Generation Output	Response

[14] AEMO Final Report: Queensland and South Australia system separation on 25 August 2018. An operating incident report for the National Electricity Market, 10 January 2019. Available at: http://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.

Synchronous	~83%[15]	As the key generation technology online during this event, response from synchronous generation was a key factor in power system outcomes. Several large generating systems either did not adjust output in response to local changes in frequency, only responded when frequency was outside a wider band than has been observed in the past, or limited, or restricted, their response to frequency changes. Large oscillatory changes in output was observed from some generating units.
Distributed PV	14%	Generally contributed to lowering frequency in SA and QLD by reducing output, but was unable to assist in VIC or NSW, as those regions needed an increase in supply. Approximately 15% of sampled systems installed before October 2016 disconnected and, of those installed after October 2016, around 15% in QLD and 30% in SA did not demonstrate the over-frequency reduction capability required by AS/NZ4777.2-2015.
Large-scale solar PV	2.3%	Generally contributed to lowering frequency in SA and QLD but did not assist in limiting the initial frequency excursions due to slow response speed.
Wind	1.2%	Did not assist in correcting the frequency deviations. Four wind farms in SA reduced output to zero due to an incorrect protection setting.
Large-scale battery	<0.1%	Assisted by containing the initial decline in power system frequency, and then rapidly changed output from generation to load to limit the over-frequency in SA following separation from VIC.

While most Generators met their obligations for frequency response under their performance standards and FCAS dispatch, the lack of frequency response from some generating systems contributed to significant technical challenges in arresting and controlling power system frequency, particularly in the earlier stages of the event.

The last time QLD separated from the rest of the NEM was on 28 February 2008, where an event in NSW led to the loss of the QLD-NSW DC interconnector, Directlink, followed by the loss of QNI. A comparison of key, relevant outcomes following the two events is detailed in Table 3:

Table 3 Event Comparison 2008 and 2018

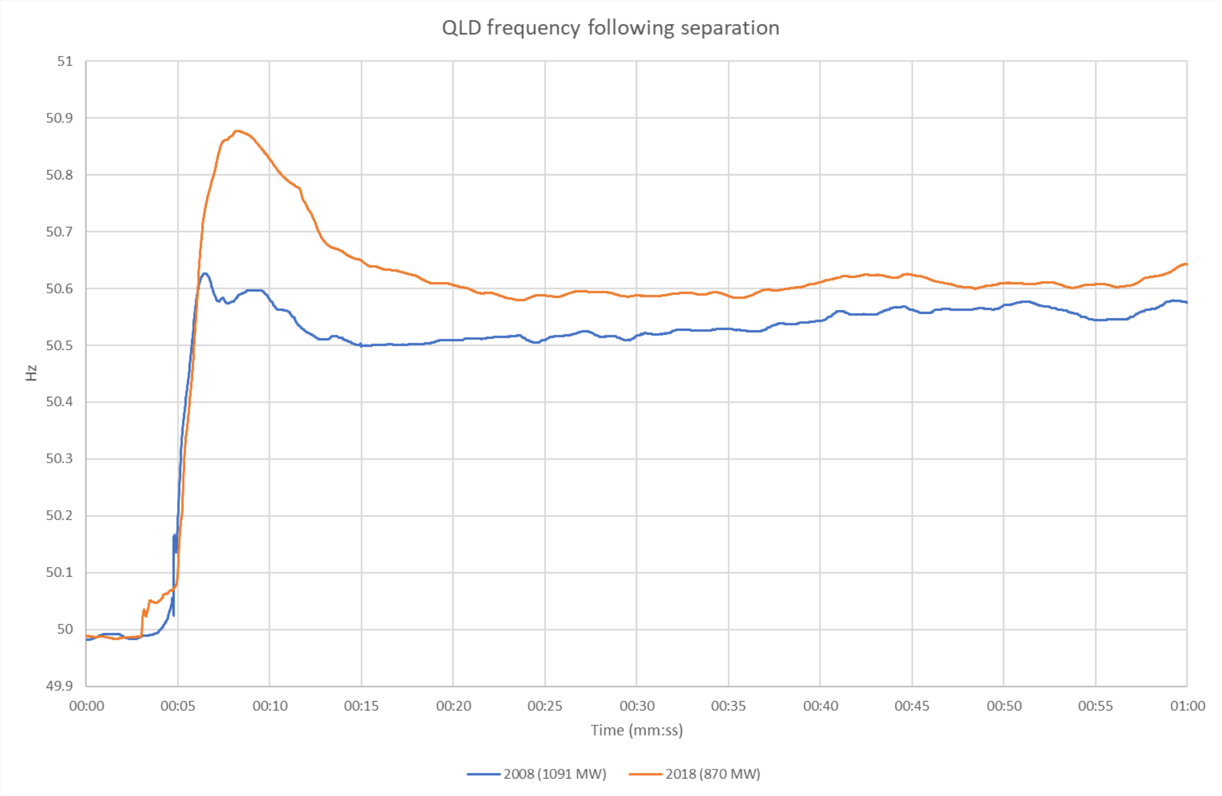
	2008	2018
Net loss of supply QLD to NSW	1,091 MW	870 MW
Other regions separated	NIL	South Australia
Maximum frequency QLD	50.62 Hz	50.9 Hz
Minimum frequency NSW	49.55 Hz	48.85 Hz
Load interrupted	NIL	997.3 MW (UFLS) 81 MW (contracted)

No two power system disturbances are ever the same, and AEMO notes that there are material differences in power system conditions between the two events, notably outside of QLD. The differences in system outcomes between the two events, however, are notable, particularly in QLD.

The spread of maximum frequency experienced in QLD in 2018 as compared with 2008 provides a clear indication that the power system's resilience to large contingencies over the last ten years has declined, as does the significant shedding of load required in 2018 to arrest an event with a similar, but larger, initiating trigger in 2008. This decline is depicted graphically in Figure 1:

[15] The percentages of output shown in Table 2 differ from those in the AEMO Incident Report because they take rooftop PV generation into account as generation, rather than demand reduction

Figure 1 QLD following separation in 2008 vs 2018



Some other observations from the 2018 event are noteworthy:

- A range of disparate frequency control actions occurred in 2018, including some that combined to exacerbate frequency deviations. Additional PFR would have counteracted or stabilised some of these outcomes.
- PFR from some new generating systems installed after the 2008 event was delayed to the point where it made little or no contribution to arresting the initial frequency deviation after the initial disturbance.
- Similar-technology asynchronous generating systems installed after 2008 tripped because of the operation of near-identical frequency protection settings and poor ongoing control of frequency.[16] Additional PFR would have reduced the likelihood of this outcome.

In AEMO's operating incident report it made several recommendations to address the decline in frequency performance, including for relevant purposes[17]:

1. AEMO to work with the AEMC, AER and Generators to establish appropriate interim arrangements, through rule changes as required, to increase PFR at both existing and new (synchronous and non-synchronous) generation connection points where feasible, by Q3 2019.
2. AEMO to support work on a permanent mechanism to secure adequate PFR as contemplated in the AEMC's Frequency Control Framework Review, to identify any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.

This rule change proposal is a response to these recommendations.

[16] AEMO Incident Report, page 87.
[17] AEMO Incident Report, pages 8 & 88.

As a result of this incident, AEMO formed the view that the decline in power system frequency performance needs to be arrested urgently. The power system cannot wait until a more comprehensive solution is developed, as envisaged in the AEMC Final Report, which could take 3-4 years until implementation.

2.6 International expert advice

While developing this rule change request, AEMO considered various models for a mandatory PFR requirement, with a key difference being the width of the frequency deadband within which PFR need not be provided. AEMO canvassed a 'wide band' requirement with NEM generators, initially set at or near the limits of the NOFB. It was initially considered that this would at least improve the resilience of the power system to large contingency events, as occurred on 25 August 2018, while minimising the ongoing impact on most generators.

However, the increasingly ineffective control of frequency within the NOFB not only exacerbates the reduction in resilience to larger disturbances, but is also of concern under normal operating conditions. Under normal conditions, the NEM exhibits ongoing poorly damped frequency oscillations, and on occasion also exhibits significant and sustained oscillations in frequency following disturbances. NEM frequency can remain near the edges of the NOFB for significant periods, often with no obvious identifiable cause. A 'wide band' requirement would not address these concerns.

AEMO therefore needed to further investigate the merits of a 'narrow band' requirement.

While the current frequency outcomes in the NEM may be broadly consistent with established regulatory obligations under the NER, a high level international comparison demonstrates they are well out of step with outcomes (and associated requirements) in comparable power systems worldwide.

To further assess the appropriateness of NEM frequency control arrangements against typical international practice, and what changes may be required to alter NEM frequency outcomes, AEMO sought the advice of a respected international consultant, Dr John Undrill.

Dr Undrill has recently prepared similar advice for FERC on US interconnection frequency control requirements[18]. He has several decades of experience in power plant control tuning, and in modelling the performance of interconnected power systems of all sizes.

Dr Undrill's report[19] for AEMO is provided as supporting information for this rule change request, and has informed AEMO's proposal on the extent of PFR needed in the NEM. This is for broad-based provision of PFR from the largest possible amount of generation, responding outside narrow deadbands.

AEMO acknowledges that, with regard to deadband settings for mandatory PFR, this proposal departs from the approach previously canvassed with a number of stakeholders. However, having regard to expert advice and considering the possible implications of **not** adopting a widespread, narrow deadband requirement, AEMO considers this represents a more prudent approach.

As a material change to recent NEM frequency control arrangements, AEMO and industry will need to work together closely to implement this change in a coordinated, efficient and effective manner.

[18] Frequency Control Requirements for Reliable Interconnection Frequency Response, John Undrill, 2018. Available at: https://www.ferc.gov/industries/electric/indus-act/reliability/frequency-control-requirements/report.pdf

[19] Refer to attachment: Notes on Frequency Control for the Australian Energy Market Operator, J. Undrill, 5 August 2019.

2.7 Other rule change proposals

2.7.1 Sokolowski proposal

On 30 May 2019, Dr Peter Sokolowski submitted a rule change proposal to the AEMC in relation to delivery of PFR from NEM generation.[20].

While there are some important areas of commonality, AEMO's proposal does differ materially from Dr Sokolowski's proposal, particularly in relation to the regulatory and practical mechanisms for implementation of a PFR requirement. AEMO has therefore elected to submit its own rule change proposal, incorporating detailed data and reasons justifying the need to include such a requirement in the NER as soon as possible.

2.7.2 AEMO proposal to remove disincentives to PFR

On 1 July 2019, AEMO submitted a rule change proposal to the AEMC requesting amendments to clauses 3.15.6A, 4.9.4, 4.9.8 and S5.2.5.11 of the NER[21] (removal of disincentives proposal). The objective of the proposal was to remove any regulatory obstacles that may be preventing Generators from providing, or continuing to provide, broad-based PFR within the NOFB. These were obstacles identified by Generators themselves.

Much of the analysis and supporting material presented by AEMO in the removal of disincentives proposal is also relevant to the requirement for mandatory PFR, and is therefore also included in this rule change proposal. However, AEMO considers them to be separate requests, targeted at addressing separate concerns with the current regulatory arrangements. For completeness, this draft rule incorporates the changes to clauses 4.9.4, 4.9.8 and S5.2.5.11 from the removal of disincentives proposal which, as a minimum, are also necessary to support a mandatory PFR requirement.

3. CURRENT FRAMEWORK

3.1 Frequency Control in the NEM

AEMO's basic obligations to manage power system frequency are set out in clause 4.4.1 of the NER:

4.4.1 Power system frequency control responsibilities

AEMO must use its reasonable endeavours to:

(a) control the *power system frequency*; and

(b) ensure that the *frequency operating standards* set out in the *power system security standards* are achieved.

Frequency, however, can only be effectively controlled if all elements of the power system are performing in a way that assists AEMO.

AEMO has recently been facing increasing challenges in maintaining frequency within the parameters specified in the FOS under normal operating conditions[22], as well as an increasing lack of effective control of frequency under normal operating conditions within the NOFB, impacting the ability to meet both of the responsibilities specified in clause 4.4.1.

[20] Rule Change Request – Amendment to National Electricity Rules Clauses <3.15.6A, 4.3.1, 4.9.4, 5.20B.5, S5.2.5.11, S5.2.5.14, 10>, Dr Peter Sokolowski, 30 May 2019. Available at: https://www.aemc.gov.au/rule-changes/primary-frequency-response-requirement

[21] Published at: https://www.aemc.gov.au/rule-changes/removal-disincentives-primary-frequency-response

[22] See the fact sheet on Regulation FCAS recently published by AEMO at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/Regulation-FCAS-factsheet.pdf.

Frequency control in the NEM is one of the AEMO power system security responsibilities under Chapter 4 of the NER.

These responsibilities arise from the operation of clause 4.3.2(a), which details AEMO's obligation to maintain power system security:

> (a) *AEMO* must use its reasonable endeavours, as permitted under the *Rules*, including through the provision of appropriate information to *Registered Participants* to the extent permitted by law and under the *Rules*, to achieve the *AEMO power system security responsibilities* in accordance with the *power system security* principles described in clause 4.2.6.

The first of the power system security principles listed in clause 4.2.6 is that AEMO is to operate the power system to maintain it in a secure operating state:

> The *power system security* principles are as follows:
>
> (a) To the extent practicable, the *power system* should be operated such that it is and will remain in a *secure operating state*.

For the power system to be in a secure operating state, it must first be in a satisfactory operating state, as detailed in clause 4.2.4(a):

> (a) The *power system* is defined to be in a *secure operating state* if, in *AEMO's* reasonable opinion, taking into consideration the appropriate *power system security* principles described in clause 4.2.6:
>
> (1) the *power system* is in a *satisfactory operating state*; and
>
> (2) the *power system* will return to a *satisfactory operating state* following the occurrence of any *credible contingency event* or *protected event* in accordance with the *power system security standards*.

To be in a satisfactory operating state, among other things, frequency must be within the NOFB specified in the FOS[23], as stated in clause 4.2.2(a):

> The *power system* is defined as being in a *satisfactory operating state* when:
>
> (a) the *frequency* at all energised *busbars* of the *power system* is within the *normal operating frequency band*, except for brief excursions outside the *normal operating frequency band* but within the *normal operating frequency excursion band*;

Schedule 5.1a of the NER sets out the system standards, to which the power system as a whole is to be planned and operated. These standards can only be met if Registered Participants meet the requirements applicable to their respective networks or connected plant in the remaining Chapter 5 schedules.

Clause S5.1a.3 states:

> The halving time of any *inter-regional* or *intra-regional* oscillation, being the time for the amplitude of an oscillation to reduce by half, should be less than 10 seconds. To allow for planning and operational uncertainties, the *power system* should be planned and operated to achieve a halving time of 5 seconds.

While it is acknowledged that system standards may not be fully met at all times at every connection point, they represent reasonably expected standards of supply that were considered consistent with good electricity industry practice. Clause 5.1a.1 expressly reflects the purpose of the system standards:

> The purpose of this schedule is to establish *system standards* that:
>
> (a) are necessary or desirable for the safe and reliable operation of the *facilities* of *Registered Participants*;
>
> (b) are necessary or desirable for the safe and reliable operation of equipment;

[23] Available at: https://www.aemc.gov.au/sites/default/files/2018-08/REL0065%20-%20The%20Frequency%20Operating%20Standard%20-%20stage%20one%20final%20-%20for%20publi....pdf.

(c) could be reasonably considered *good electricity industry practice*; and

(d) seek to avoid the imposition of undue costs on the industry or *Registered Participants*.

3.2 Tools available to AEMO to control frequency

The tools currently available to AEMO under the NER to manage frequency are the market ancillary services and emergency frequency control schemes, such as load shedding or generation shedding. Under certain emergency conditions, directions to participants to assist in controlling frequency may be required.

However, neither directions nor emergency frequency control schemes have a role in controlling power system frequency under non-emergency conditions.

3.2.1 Market ancillary services

Market ancillary services are the key mechanism provided under the NER for control of power system frequency – both under normal conditions, and following the occurrence of a credible contingency or protected event.

At first glance, the requirements specified in the MASS look like they should operate to keep power system frequency close to 50 Hz. However, they act only to maintain or restore power system frequency **somewhere within the NOFB** under normal conditions, and to arrest and restore frequency to within this band following a credible contingency event, because:

- Contingency FCAS only must be provided after power system frequency exits the NOFB, namely upon the occurrence of a contingency event. It is not designed to play any role in controlling power system frequency under normal operating conditions.
- Regulation FCAS is the only mechanism designed to control power system frequency under normal operating conditions to enable AEMO to fulfil its obligations under clause 4.4.1(a) of the NER. It is intended to allow for the control of power system frequency close to the normal level of 50 Hz in the absence of any disturbance but is capable of doing so only when supported with adequate PFR.

The tools currently available to AEMO do not facilitate the effective control of frequency under normal conditions, and instead result in an arrangement where frequency is moving in an increasingly uncontrolled manner across the entire 300mHz range of the NOFB.

3.2.2 Load shedding

The NEM has automatic UFLS, which is an emergency feature of all conventional power systems. It is not a tool for control of frequency under any normal operating conditions, but rather it is a last line of defence to avert a power system collapse following a supply-demand mismatch that cannot be corrected by any other means.

UFLS is a very blunt way to manage the balance of inflows and outflows on the power system and is a very costly option for impacted consumers. Due to both physical limitations, and the need to ensure robustness, UFLS lacks the precision needed to keep supply and demand closely matched, often resulting in more load being shed (and a longer period of outage) than is strictly necessary.

Increased provision of PFR in the NEM as a result of this rule change would ensure that UFLS always functions as it was designed, that is as a measure of last resort where no other options exist, rather than as a measure to be activated for events that simply exceed the design of the Contingency FCAS frameworks.

3.2.3 Generation shedding

Automatic disconnection of generation under extreme high frequency conditions, also referred to as over-frequency generator shedding (**OFGS**) is, essentially, the inverse of UFLS. As with load shedding, it is an extreme response to the problem and is supposed to be a last resort for use in emergencies where other options are not available. OFGS has been a long-term feature in some regions and is being installed or considered for use more widely across the NEM. Like UFLS, it lacks precision and results in larger and more prolonged consequences than are technically required to correct imbalances.

OFGS occurred on 25 August 2018, when generation in QLD was disconnected automatically by protection systems in response to sustained high frequency conditions.

3.2.4 Protected events

The protected events framework allows AEMO to recommend a non-credible contingency be classified as a protected event, allowing AEMO to take operational action to manage the risk within the parameters declared by the Reliability Panel. The first protected event was declared on 20 June 2019 for South Australia.

The protected events framework addresses only non-credible contingencies specifically identified as part of a Power System Frequency Risk Review. It requires a protected event to be specifically identified prior to its occurrence, and allows for a targeted and specific strategy to be developed to manage that event. It does not provide for general power system response to previously unidentified contingency events, or categories of similar or related events.

3.3 Generator obligations to support frequency control

3.3.1 Obligation to meet performance standards

While AEMO is responsible for the management of power system frequency in the NEM, Generators are required to support AEMO in this endeavour by meeting their performance standards related to frequency, as stated in clause 4.4.2(b) of the NER:

> **4.4.2 Operational frequency control requirements**
>
> To assist in the effective control of *power system* frequency by *AEMO* the following provisions apply:
>
> …
>
> (b) Each *Generator* must ensure that all of its *generating units* meet the technical requirements for frequency control in clause S5.2.5.11;

Most of the technical requirements in clause S5.2.5 specify an automatic access standard and a minimum access standard and, in some cases, additional parameters for a negotiated access standard. The automatic access standard is the most onerous, and the minimum access standard provides a minimum requirement that might be acceptable in appropriate circumstances. A negotiated access standard may be agreed somewhere between the minimum access standard and the automatic access standard but, since 5 October 2018, must be as close as possible to the automatic access standard. [24]

Clause S5.2.5 was amended on 27 September 2018 by the *National Electricity Amendment (Generator technical performance standards) Rule* 2018 No. 10.

[24] Following commencement of the National Electricity Amendment (Generator technical performance standards) Rule 2018 No. 10. Clauses 5.3.4A and 5.3.9 prescribe the process for approval and agreement of technical standards on connection or alteration of a generating system.

Clause S5.2.5.11 was one of the provisions amended. The automatic access standard in clause S5.2.5.11 requires Generators to be **capable** of operating their generating systems in a way that is responsive to changes in power system frequency such that the Generator can offer measurable amounts of all market ancillary services for power system frequency control.

The minimum access standard merely requires that generating systems are **capable** of operating in frequency response mode.

Notably, the general requirement in clause S5.2.5.11(i)(4) states:

(4) a *generating system* is required to operate in *frequency response* mode only when it is enabled for the provision of a relevant *market ancillary service*;

This clause could be interpreted as suggesting a generator can, or even should, operate in a mode where its output is not sensitive to frequency at any time when it is **not** enabled for the provision of a relevant market ancillary service. Such behaviour reduces the levels of PFR in the NEM, and does not support ongoing control of power system frequency.

3.3.2 PFR outside FCAS markets

Other than the Contingency FCAS markets, there is currently no arrangement that directly obliges (or rewards) delivery of PFR from any generating system to support ongoing frequency control inside or outside the NOFB, with the exception of emergency arrangements for extreme frequency events.

This increasingly leaves AEMO only able to rely on the PFR provided through Contingency FCAS to manage power frequency under almost all conditions. In the case of disturbances, they must manage not just the credible contingency events for which the Contingency FCAS market is designed, but all events resulting in frequency changes.

4. STATEMENT OF THE PROBLEM

4.1 Issue overview: Decline in control of power system frequency

As noted in Sections 2 and 3:

- AEMO is increasingly unable to control frequency in the NEM under normal operating conditions, due to reduced provision of PFR from generation.
- The tools currently available to AEMO cannot effectively control frequency on an ongoing basis, and are increasingly resulting in power system outcomes that AEMO now regards as inconsistent with prudent industry practice.

Power system frequency under normal conditions is increasingly moving in an uncontrolled manner across the full frequency range allowed for within the NOFB, and AEMO is left with only slow, centralised adjustment of generator setpoints via AGC control, to try and control fast moving power system frequency, a task for which this arrangement is fundamentally unsuitable.

The power system is demonstrating ongoing oscillations of frequency which do not meet established norms for damping of power system oscillations consistent with good electricity industry practice.

The resulting frequency performance of the NEM is outside the bounds and experience of frequency in other comparable power systems. In a rapidly changing power system environment, particularly with increasing levels of inverter interfaced generation, of which there is little very long-term experience worldwide, it makes it difficult to leverage learnings from other comparable power systems when the basic operating practices of the NEM regarding frequency control are increasingly far out of line with international norms.

Declining frequency performance also reduces the resilience of the power system to disturbances, particularly any disturbance that is greater than a single credible contingency event. This has two consequences:

- It increases the reliance on emergency frequency control schemes to manage such events, and with that reliance increases the risk of cascading failures leading to system collapse.
- It reduces AEMO's ability to model and analyse the performance of the power system (especially for complex dynamic behaviour), which is essential for AEMO's ongoing management of power system security.

Sections 4.2 and 4.3 provide analysis of the causes and implications of the decline, and Section 4.4 explains why existing tools (primarily the FCAS markets) are inadequate to address it.

4.2 Causes of declining frequency performance

4.2.1 Factors that normally impact power system frequency

Frequency will change when there is a supply-demand MW mismatch. The frequency performance of the power system is determined by:

- The MW imbalance between instantaneous supply and demand, which can have many individual underlying causes.
- The total frequency response provided by all generation to the frequency changes that arise from these MW imbalances.

The MW imbalance between supply and demand can occur at varying levels, be caused by a variety of factors, and occur over a variety of timeframes. Causes include:

- Demand changing constantly within a dispatch interval, with both predictable and random components, over timeframes of seconds to minutes.
- Demand forecasting errors, requiring correction over market dispatch timeframes.
- Supply forecasting errors, such as:
  - Forecasting inaccuracy in AWEFS, AEMO's wind energy forecasting system, as noted by DIgSILENT in a report prepared for AEMO and submitted to the AEMC during its Frequency Control Frameworks Review.[25]
  - Unexpected changes in weather conditions impacting solar- or wind-dependent generation output, particularly changes inside the 5-minute dispatch cycle.
- Sudden contingency events, such as:
  - Tripping or disconnection of generation, load or transmission lines connecting them.
  - Simultaneous response of inverter-controlled plant to a change in power system conditions, such a fault or other system disturbance at the distribution or transmission level. The potential impact of widespread simultaneous response is greater when frequency is not effectively controlled.

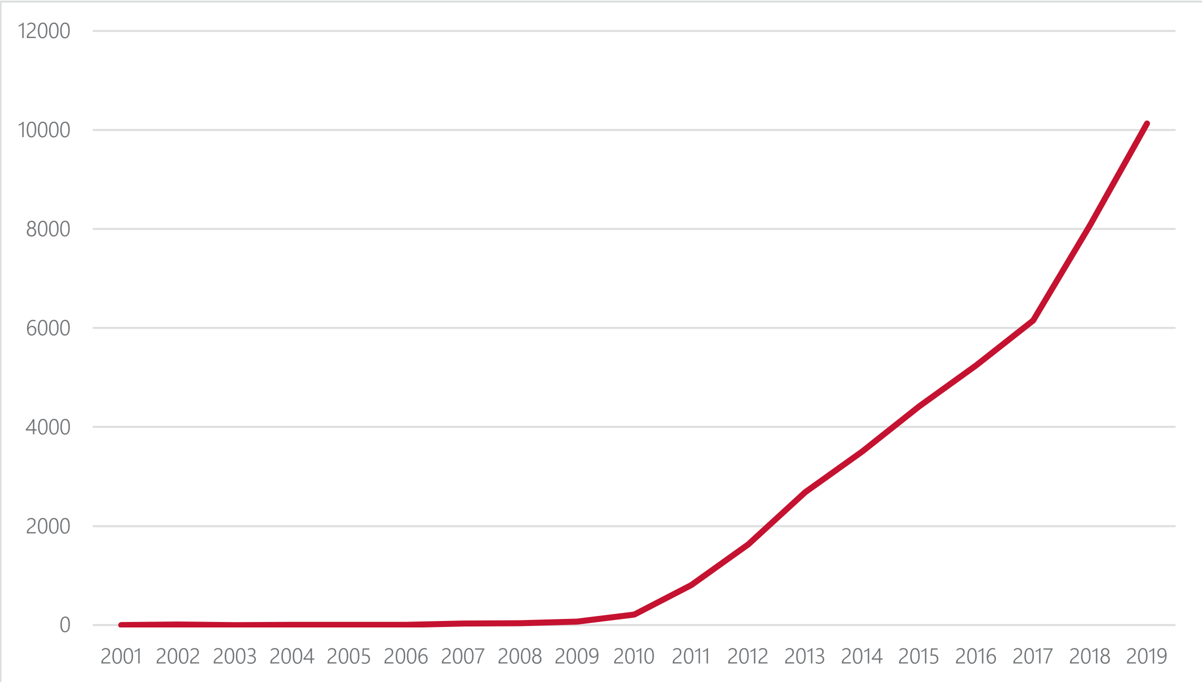
[25] DIgSILENT Pacific, Review of Frequency Control Performance in the NEM under Normal Operating Conditions, 19 September 2017. Available at: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf.

4.2.2 Increased risk of future large supply-demand mismatches

The impact of some of the factors normally affecting supply-demand imbalance is expected to increase over time. One of these is the large forecast increase in solar PV generation (rooftop and large scale) in the NEM.[26]

Data from the Australian PV Institute Solar Map shows that PV generation in Australia has grown at a rapid rate, as demonstrated by Figure 2:

Figure 2 Cumulative installed solar PV in Australia (MW)



Ten years ago, the amount of solar PV generation barely registered as a proportion of total connected generation. The Australian PV Institute estimates that, as of 30 September 2018, there were over 1.95 million PV installations in Australia, with a combined capacity of over 10.14 GW. If the estimated contribution of Western Australia and the Northern Territory is deducted (about 11%), that leaves around 9.02 GW of installed PV out of a total of 50.654 GW of generation (around 18%) in the NEM[27].

In its most recent Electricity Statement of Opportunities, AEMO forecast a total installed solar PV capacity in the NEM of over 40 GW by 2038, with around 20 GW of this comprising distributed rooftop PV.[28].

Large grid-scale PV generation installations can be subject to rapid cloud shadowing, resulting in material short-term output changes. This introduces a short-term MW imbalance that will manifest as a frequency change if not corrected.

The increasing numbers of small, distributed PV installations also increase the risks associated with the involvement of this generation in major power system disturbances, as was seen on 3 March 2017 in SA[29], and across the NEM on 25 August 2018. Disconnection of up to 40% of distributed PV in SA following

[26] AEMO observations: Operational and market challenges to reliability and security in the NEM, March 2018. Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.pdf.

[27] Data sourced from Australian PV Institute website at: http://pv-map.apvi.org.au/. Total *NEM generation* sourced from AEMO's Generation Information Page at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[28] See page 27. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

[29] See AEMO's report on Fault at Torrens Island Switchyard and Loss of Multiple Generating Units on 3 March 2017. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf.

transmission faults on 3 March 2017 greatly increased the complexity and severity of this event. The unexpected response of distributed PV, including both disconnection and failure to reduce output in line with applicable standards, complicated the event on 25 August 2018[30].

The involvement of distributed PV generation in system disturbances increases the risk of cascading events in a way that is difficult to quantify. This is a particular risk as the performance characteristics and disturbance response of distributed PV are far less closely characterised, specified and managed than those for large, registered PV generation. This increases the risk that initial contingency events may, or may not, cascade into larger events, depending on the often unpredictable aggregate response of distributed PV.

4.2.3 Fewer generating units are now providing PFR

For many decades, widely distributed control has been used worldwide for frequency control, involving many generating units making small incremental changes to keep frequency close to nominal, and providing response proportional to their size following a disturbance.

This was achieved through the near-universal specification of droop characteristics under which each generating system modulates its output by an amount proportional to their capacity in response to locally measured frequency changes[31]. Under this arrangement almost all generation was always required to provide PFR in line with certain specifications.

The distributed nature of this control arrangement provides resilience by ensuring the largest pool of potential providers of PFR, and minimising the consequences if any provider does not respond as expected, or is unable to respond to a given event, say, due to a partial break-up, or separation, of portions of the network.

Because all PFR generating systems respond together in proportion to their size, the duty on any individual generating system is minimised in a distributed design, both under normal conditions, and following disturbances. This arrangement also ensures power flow changes on the network in response to an event are kept small, minimising the consequential impacts of disturbances.

This broadly distributed design was how frequency response was managed in the NEM prior to establishment of the FCAS markets in 2001. Contractual arrangements were used in parallel to these control system designs to ensure minimum levels of MW reserve were available for the delivery of PFR, particularly under conditions of high demand, where response headroom could otherwise become scarce.

In practice, these distributed control arrangements persisted for many years after establishment of the FCAS markets, as it was collectively embedded into the control strategies of many generating units built prior to establishment of the NEM, and these control systems would have to be collectively altered to change this overall system control philosophy.

The design of the FCAS markets does not require distributed PFR from all generation, but allocates frequency response obligations to only those few who elect to participate in the FCAS markets, and are dispatched in any 5-minute period to hold MW reserves for the delivery of PFR. It increases the control burden on those who do participate, compared to arrangements where provision of frequency response is near universal.

Generation control arrangements have been adjusted gradually, particularly over the last several years, to increasingly align with the underlying principles and settings of the FCAS markets. A significant proportion of generation that previously provided continuous PFR, is now increasingly unresponsive, particularly under normal operating conditions, unless enabled for FCAS.

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[30] AEMO Final Report: Queensland and South Australia system separation on 25 August 2018. An operating incident report for the National Electricity Market, 10 January 2019. Available at: http://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

[31] See section 11.1, Prabha Kundur, Power System Stability and Control. (McGraw-Hill, 1994)

4.2.4 Generator survey results

The results of surveys conducted by DigSILENT (2017)[22] and AEMO (2018) of generator frequency control settings indicate that many major power stations are still providing some PFR at varying degrees of frequency change, and their response levels may vary with market and operational conditions. Generators identified a number of regulatory, technical or economic reasons for limiting or modifying their PFR response. These are canvassed in AEMO's recently submitted rule change proposal: Removal of disincentives to the provision of primary frequency response under normal operating conditions.[32]

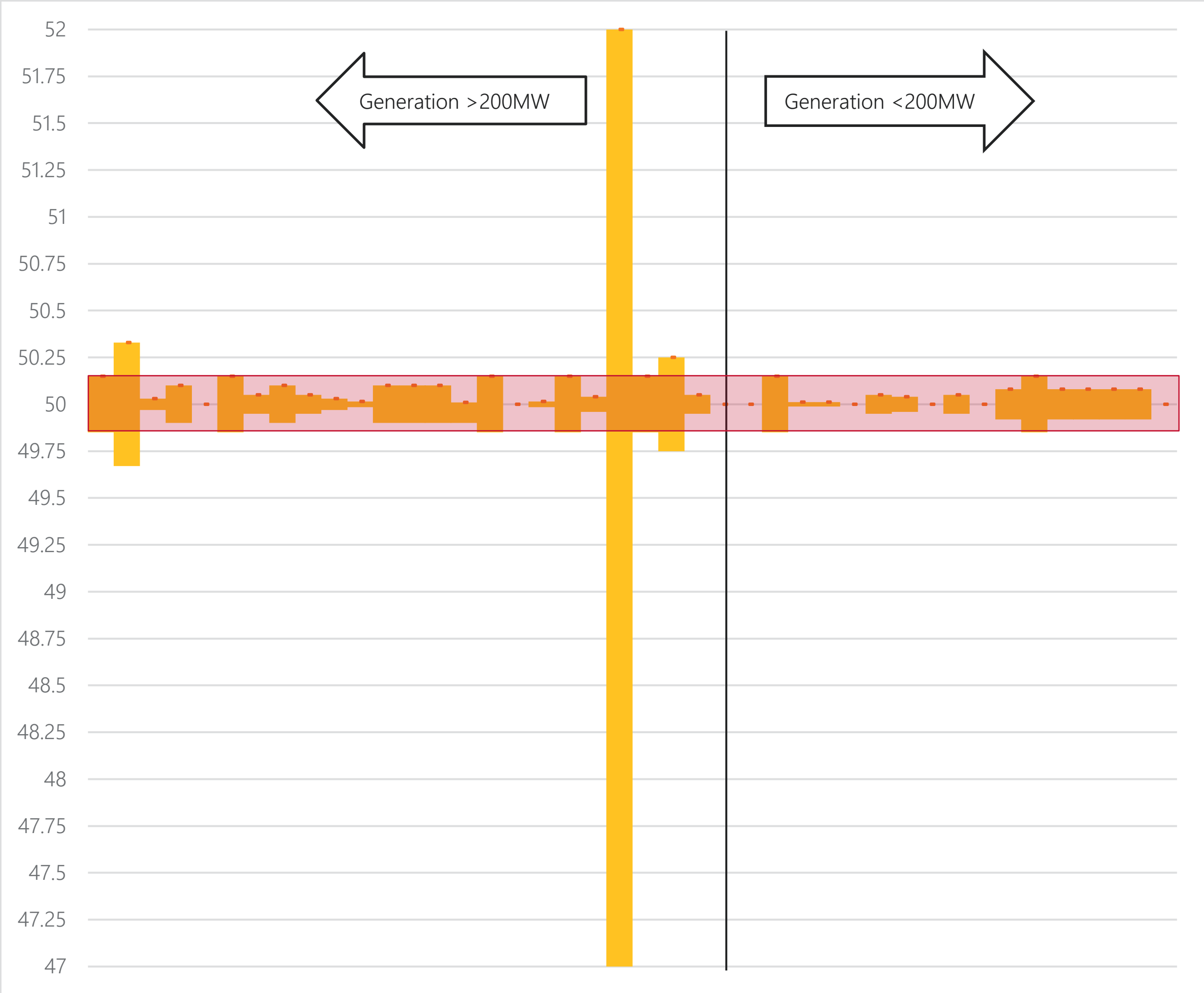
AEMO received data on a total of 45 scheduled generating systems, representing 32,036.6 MW of NEM capacity (around 70%). Of these, details of frequency response settings were provided for 37, representing 25,785 MW of NEM capacity (around 60%)[33]. Figure 3 depicts deadbands applied as part of these frequency response settings against the NOFB, which is represented by the red horizontal bar. The chart also indicates whether the surveyed scheduled generating systems have a capacity of more, or less, than 200 MW.

Note that the frequency deadbands indicated in Figure 3 may be within speed governors on rotating machines, in plant load controllers, or in both, depending on the control system design in use at the plant. The application and behaviour of frequency response settings on the unit can also vary depending on whether the unit is enabled to provide MW response reserves via the Contingency FCAS markets, and other operational or market outcomes.

[32] Published at: https://www.aemc.gov.au/rule-changes/removal-disincentives-primary-frequency-response

[33] The remaining generating systems were stated as either having no setting or information was not provided.

Figure 3 Frequency response deadbands in use (based on survey results)



The survey identified that only 12 of these scheduled generating systems (around 15% by capacity) always operate in frequency response mode using consistent frequency response settings, while another seven only do so when not restricted by other operational factors, such as temperature.

Six generating systems only provide frequency response when enabled for FCAS. For the remaining generating systems, there was insufficient information as to the frequency with which they were operated with the stated governor settings.

4.3 Implications of declining performance

4.3.1 Difficulty meeting the Frequency Operating Standard

The Reliability Panel's 2018 Annual Market Performance Review[34] noted that the NEM's frequency performance has continued to deteriorate. Some requirements of the FOS for normal operation were not met in both the mainland and Tasmania during 2017-18:

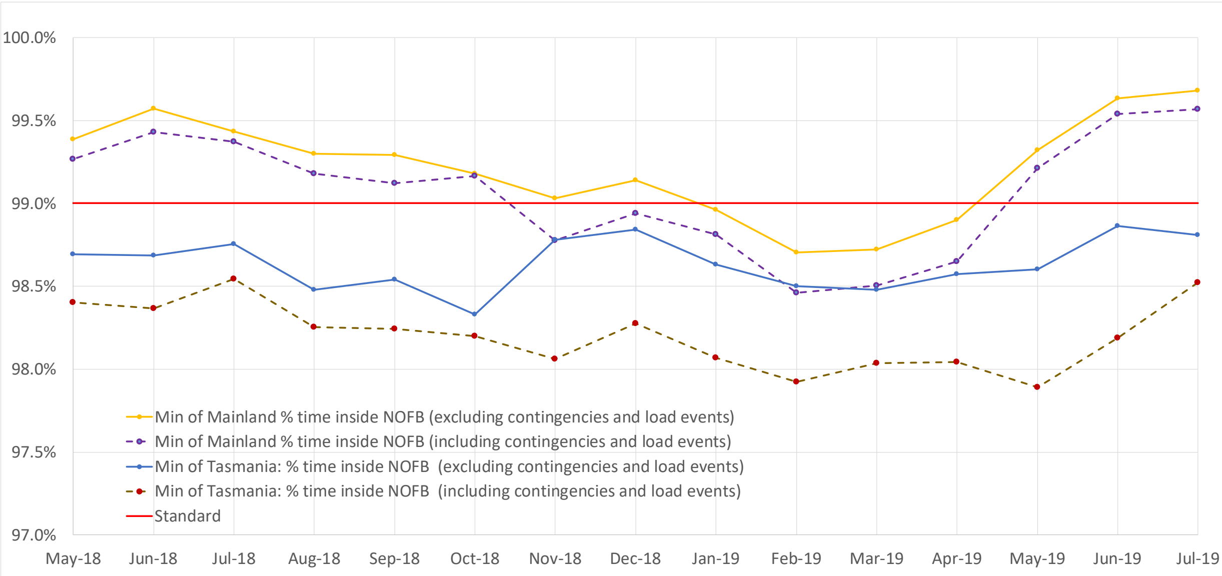
- On the mainland, frequency remained within the NOFB more than 99% of the time but there were 50 events where frequency took longer than allowed in the FOS to be returned to the NOFB following a disturbance.

[34] Available at https://www.aemc.gov.au/market-reviews-advice/annual-market-performance-review-2018.

- In Tasmania, frequency performance was poorer, where it was outside of the NOFB for more than 1% of the time for 11 months. Further, there were 295 events where frequency took longer than allowed in the FOS to be returned to the NOFB following a disturbance.

While frequency control is AEMO's responsibility under the NER, the reality is that AEMO cannot control frequency effectively within the NOFB without assistance from plant capable of responding appropriately to frequency changes in the power system to improve frequency outcomes. Figure 4 shows rolling 30-day averages of frequency in the mainland and TAS since May 2018. Between May and October 2018, performance continued to decline, while Regulation FCAS quantities remained unchanged. With frequency consistently below the requirements of the FOS in early 2019 in both the mainland and in Tasmania, AEMO began a series of staged increases in Regulation FCAS quantities. While mainland performance has been brought back within the target range, Tasmania remains stubbornly below. It is interesting to note that mainland frequency performance now approximates the that observed in mid-2018, despite a ~70% increase in base procurement of Regulation FCAS.

Figure 4 Minimum 30-day rolling average of percentage of time frequency within the NOFB



4.3.2 Ongoing instability in NEM frequency

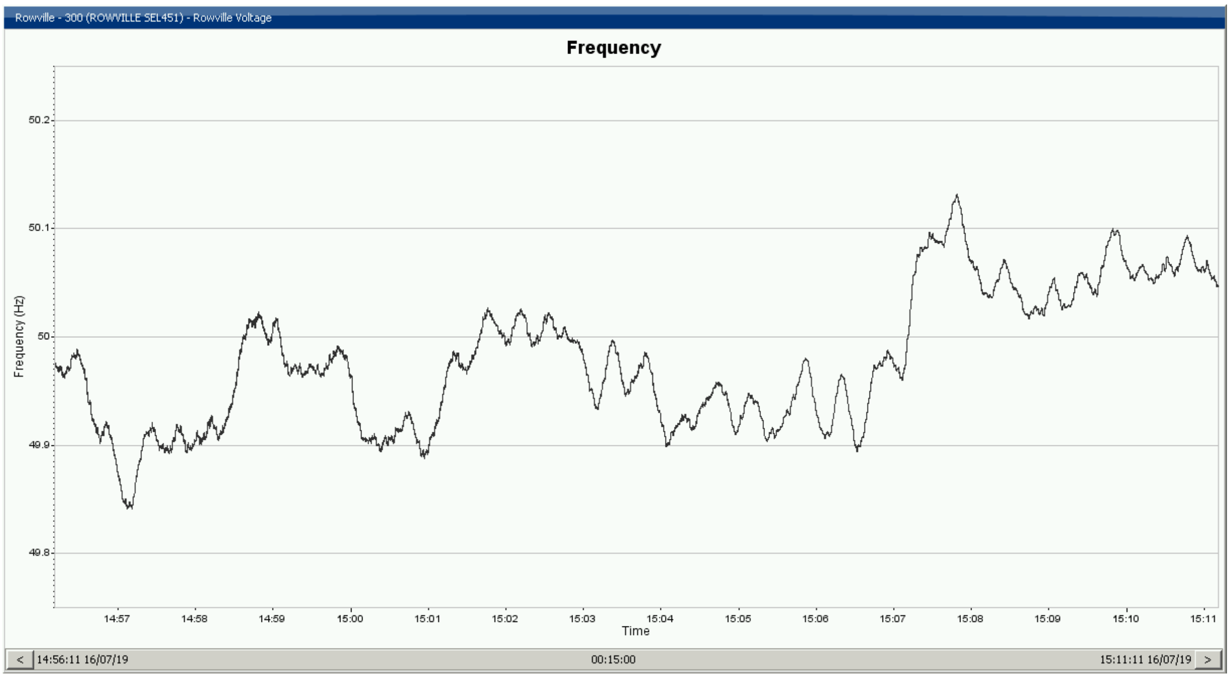
Under normal operating conditions frequency in the NEM is increasingly not in fact controlled, but is moving in an uncontrolled manner between the boundaries of the NOFB, in response to the accumulation of random changes in demand and generation that occur on an ongoing basis.

Frequency in the NEM is also exhibiting oscillatory frequency movements on an ongoing basis. NEM frequency under normal conditions increasingly exhibits continual oscillations with a period of 20-30 seconds. On-line monitoring tools available to AEMO indicate that the halving time of these oscillations routinely exceeds the 5 second halving time standard outlined in the NER.

It should be noted that these frequency changes are not the small, low amplitude ongoing oscillations in frequency that are observed due to inter-area rotor angle oscillations between groups of machines across the interconnection. These inter-area oscillations can be, and are, well damped through appropriate design of generator excitation systems, in particular the use of power system stabilisers.

The observed long period oscillations in NEM frequency are instead common mode changes in frequency, involving all machines across the power system speeding up or slowing down in unison with each other. A typical 15 minute measurement of NEM frequency is shown below in Figure 5, where the periodic 20-30 second oscillations in system frequency can be clearly observed.

Figure 5 NEM frequency measurement showing ongoing periodic oscillations



4.3.3 Power system events are becoming more complex

On some occasions and over some timeframes, real power system disturbances deviate significantly from the simple credible contingency events considered in the FCAS markets design, even though the initiating event for the disturbance may be credible, or at least foreseeable.

The ongoing increase of small, distributed PV tends to increase the size of deviations when larger power system disturbances occur, as was seen on 3 March 2017 in SA, and across the NEM on 25 August 2018.

In the power system event on 25 August 2018, two large synchronous generating units exhibited significant oscillatory behaviour in their MW output. When PFR is limited to a small number of providers, the power system has lower immunity to detrimental behaviour of individual plant, as each item of plant has a greater ability to affect power system frequency. A power system with PFR from a wider range of providers has much greater control and can resist or damp power system outcomes that result from one, or a group of mal-operating generating units.

Operation of areas of the power system under low system strength conditions increases risks related to unexpected or undesirable control behaviours from power electronic interfaced generation. On an ongoing basis across more than one region, AEMO is reclassifying certain events as credible subsequent to voltage disturbances, such as disconnection of large loads or HVDC links. . This can greatly increase the range, complexity and MW size of potential outcomes for which AEMO needs maintain power system security.

Conservative allowances can potentially be made for some of these factors in FCAS dispatch outcomes. However, improved power system resilience to a range of often inherently unpredictable disturbance outcomes is a more logical response to the changing nature of the power system and its behaviour following these more complex disturbances.

4.3.4 Increased reliance on load shedding

A reduction in the availability of PFR following a frequency disturbance involving significant loss of supply will necessarily increase the potential for UFLS schemes to be activated. The Contingency FCAS design was intended to ensure both adequate delivery of PFR and adequate MW reserves to arrest a decline in frequency following a simple credible contingency event before it reaches the level where UFLS will be activated. However, the design does not ensure any margin exists beyond these levels.

Ineffective control of frequency close to the NEM design value of 50 Hz allows frequency outcomes at the lower edge of the NOFB on a regular basis. This further increases the potential for load shedding by eroding the NOFB buffer.

AEMO considers it is essential to rebuild and maintain these margins to provide resilience against the more complex events now occurring on the power system, which are unpredictable in extent and increasingly go beyond the simple contingency events considered in the Contingency FCAS market design. It is not acceptable to operate with no resilience against events that exceed the Contingency FCAS market design and, by design, to proceed immediately to involuntary interruption of customer load.

Ensuring more widespread provision of PFR across the NEM, both within the NOFB and following larger power system disturbances, would be an effective mechanism to ensure UFLS remains, as it should be, a last resort emergency response.

4.3.5 Reduced ability to learn from comparable power systems

The NEM is increasingly operating with world-leading penetration levels of inverter connected generation. With respect to matters such as grid strength, system stability and system modelling the NEM is arguably operating at the very edge of existing knowledge and experience. Simultaneously, it is operating with levels of ongoing frequency variability that are well outside long standing international norms and experience.

This combination of factors makes it far more difficult for AEMO to learn from or apply the experience of other system operators worldwide regarding the appropriate management of high levels of inverter connected generation in relation to frequency response and control arrangements, as the underlying power system conditions into which the new inverter connected generation is being introduced are simply not comparable with international experience. Consequently, the NEM is more exposed to the risk of experiencing rare or previously unknown interactions or phenomena.

Improving NEM frequency control in normal conditions through increased provision of PFR would facilitate comparisons with international power systems, and improve the ability to apply learnings from the experiences of operators of other similar power systems. This is an important factor in the discussion in Section 12.2 about the size of allowable frequency response deadbands.

4.3.6 Less predictable power system plant behaviour

Tools and models

It is common for power system operators to include frequency assessments as part of their dynamic security assessment tools, which run dynamic simulations to confirm power system security close to real-time. With the rapid changes affecting power systems globally, these tools are becoming increasingly important.

Models that consistently and accurately simulate the frequency performance of generating units are a prerequisite to developing these tools. A lack of consistency and certainty of PFR delivery from generation when making these assessments makes these tools less accurate, and, consequently, less useful[35]. It also

[35] As noted in Section 0.

creates uncertainty about the true operating limits of the power system. Simple and predictable requirements for generation to provide PFR increase confidence in the use of these tools.

A requirement for provision of PFR with consistently applied settings would greatly narrow the range of possible responses from connected plant that could be expected during a power system incident. This makes the simulation of events, including non-credible and complex events, more realistic for planning studies and incident investigation.

Understanding the causes of power system incidents

When AEMO commenced analysis of the power system event that occurred on 25 August 2018, difficulties were experienced when attempting to simulate and predict the response of generation, particularly in QLD for the critical period immediately after the initial disturbance. In some cases, there were large differences between the response predicted by the available simulation models, and the actual observed responses.

None of the generation in QLD was enabled to provide Contingency FCAS in response to the high frequency during this event, and yet many Generators that were not obliged to do so responded in a manner that was supportive of control of power system frequency. Some generating units were limiting or restricting their response to this large disturbance to align with their FCAS capabilities. This is not considered in the available simulation models.

In other cases, suitable simulation models for generation were not available. Given that there is no underlying requirement for generation to respond to frequency outside of that required by the FCAS markets, it was unclear what, if any, assumptions could be made about the likely frequency response of those generating units.

This has the potential to undermine the effectiveness of the *National Electricity Amendment (Generating System Model Guidelines) Rule* 2017[36].

Ability to design and operate emergency frequency control schemes

In this increasingly complex environment there is a need for predictable, consistent and modellable generator behaviour to facilitate good planning. An example is the design of UFLS, OFGS and other emergency frequency control schemes, which cannot be carried out in isolation from the expected delivery of PFR from generation. Planning these schemes requires consideration of the quantity and dynamic performance of available PFR. Unnecessarily conservative assumptions can be required when designing these schemes if existing market arrangements ultimately form the only guarantee of any provision of PFR.

If generator control system parameters change dynamically based on FCAS enablement, the range of possible responses from generation becomes very broad, complicating scheme design and, potentially, compromising scheme performance. The aggregate response of the power system can change quickly due to control parameters being changed without AEMO’s knowledge because is not reflected in generator models. Designing schemes based only on the PFR available from the FCAS markets would likely lead to overly conservative assumptions and sub-optimal settings.

4.4 Existing tools cannot address decline

4.4.1 Market ancillary services cannot deliver control

On their own, market ancillary services have proven inadequate to address the challenges AEMO faces to control power system frequency. In fact, as the generation landscape has evolved, the FCAS markets have arguably contributed to the withdrawal of PFR under the majority of operating conditions, because the way

[36] Available at: https://www.aemc.gov.au/sites/default/files/content/3e5e1b77-d56d-4935-ba11-ace3b687aa2c/Generating-System-Model-Guidelines-ERC0219-Final-Determination.pdf.

AEMO measures the provision of Contingency FCAS, as specified in the MASS, incentivises the delayed delivery of PFR until power system frequency is outside the NOFB.[37]

The withdrawal or limitation of PFR has resulted in the decline of frequency control under normal operating conditions, leaving the power system increasingly dependent on Regulation FCAS alone under most operating conditions.

Regulation FCAS is a form of secondary frequency control, dependent on centralised measurement of frequency at one of AEMO's control centres, and subsequent adjustment of generator setpoints via SCADA, as determined by AEMO's centralised AGC system.

- Once it has measured frequency, AGC takes at least 4-8 seconds to begin issuing commands to generating units to correct frequency deviations.
- AGC includes deliberate smoothing of generator control responses, further reducing response rates from many generators.
- Generator response is not synchronised, but rather generators respond at varying rates as dictated by their market or SCADA ramp rates and inherent secondary control delays.

AGC is a slow response control system, which cannot, by definition provide stable control by itself of a variable such as frequency, that is moving faster than the response times of that control system. Regulation FCAS and AGC form a secondary control system, that by definition, only acts to adjust the setpoints of the primary control systems which actually act to control frequency.

The fundamental limitations of this form of control means that further tuning or adjustment of AGC performance alone will not produce significant improvement in power system frequency outcomes, particularly in increasing the stability of power system frequency under normal operating conditions, or the resilience of the power system to disturbances.

4.4.2 Reliance on Contingency FCAS providers reduces system resilience to disturbances

The NEM is trending towards a power system that concentrates primary frequency response (outside the NOFB) amongst a select few generating systems, based on wherever frequency response reserves are cheapest in any 5-minute period.

If this trend continues to its logical end-point, the only PFR during and following a contingency event would be that provided by those few generating units enabled to provide Contingency FCAS. If this happened, the NEM would be the only large power system in the developed world operating to such a design. By this point:

- Any redundancy or safety margins in PFR would be removed.
- It would be critical for all Contingency FCAS providers to behave exactly as required, which based on operational experience is a highly unrealistic expectation in all circumstances.
- The resilience against any behaviours or responses beyond the simple contingency events considered in the market design would be reduced, or removed.
- Power system performance following non-credible contingency events would be increasingly uncertain, and dependent on FCAS that was not intended to manage the types of more complex events to which the NEM is now more exposed.
- The ability of island regions, or sub-regions, to meet FOS standards for recovery following major disturbances would be reduced.

[37] AEMO intends to consult on changes to the MASS to proposes

4.4.3 Protected events framework unable to address the issue

The protected events framework allows AEMO to recommend a non-credible contingency be classified as a protected event, allowing AEMO to take operational action to manage the risk within the parameters declared by the Reliability Panel. To date only one protected event has been recommended, and that has not yet been declared by the Reliability Panel.

The protected events framework has no role to play in the management of frequency under normal operating conditions, which is the focus of AEMO's rule change proposal.

While it can be used to address the potential consequences of specifically identified contingency events, AEMO considers that the protected events framework has a number of shortcomings, noted with the benefit of experience since the framework was introduced in 2017. These include:

- The time needed to identify, develop, review and eventually declare a protected event is too long to keep pace with the rapid transition in the power system. This leaves no option but for AEMO to intervene where it is possible to do so, often in costly ways. In that time, the rapid pace of change in the network means that the nature of the risk will most likely have changed, and different challenges may be presenting.
- The protected events framework only addresses risks of non-credible contingencies in the context of dispatch and real time system security management. In practice it will never be possible to identify, in advance, every discrete non-credible contingency that would have an unacceptably high impact if it occurred. In effect, most of the risk of high impact, low probability events will remain un-mitigated through this mechanism.

For these reasons, general improvements in physical system resilience with broad applications to many events, such as increased provision of PFR under all operating conditions, are likely to be far more efficient and effective than using the protected event framework to target individual circumstances.

5. HOW THE PROPOSAL WILL ADDRESS THE ISSUE

5.1 Objectives

AEMO seeks to:

- Re-establish effective control of power system frequency, and thereby align the NEM with standard international practice.
- Increase the resilience of the power system to disturbances, particularly events beyond simple credible contingency events.
- Ensure a predictable frequency response from generation to power system disturbances, to support power system planning and modelling.

5.2 How the proposed rule addresses the issue

To address the issues described in this document, AEMO considers that clause 4.4.2 of the NER should require all capable scheduled and semi-scheduled generation to provide PFR when frequency is outside a specified narrow frequency response band.

The proposed rule will require AEMO to specify the technical characteristics of the PFR Generators must provide in a separate instrument, which will be a consulted document under the NER.

The proposed rule will facilitate effective control of power system frequency, through more predictable and widespread provision of PFR, both for small changes in frequency under normal operating conditions and following contingencies.

It will make the power system more resilient and will enhance the power system's response to disturbances, will support better power system planning and modelling which, in turn, will lead to better management of power system security and reliability.

The proposed rule is described more fully in Section 12.

5.3 Affected Generators

All technically capable scheduled and semi-scheduled generation would be affected by this proposal.

A significant proportion of NEM generation is already providing or capable of providing PFR to varying degrees, and via various control arrangements. It is expected that many Generators would not need to make substantive changes to their plant control systems to meet the requirements of the proposed rule, other than perhaps reducing the deadbands outside which frequency response was delivered, or selecting their plant load controllers to operate in a manner that supports frequency response from the plant rather than limiting or defeating it.

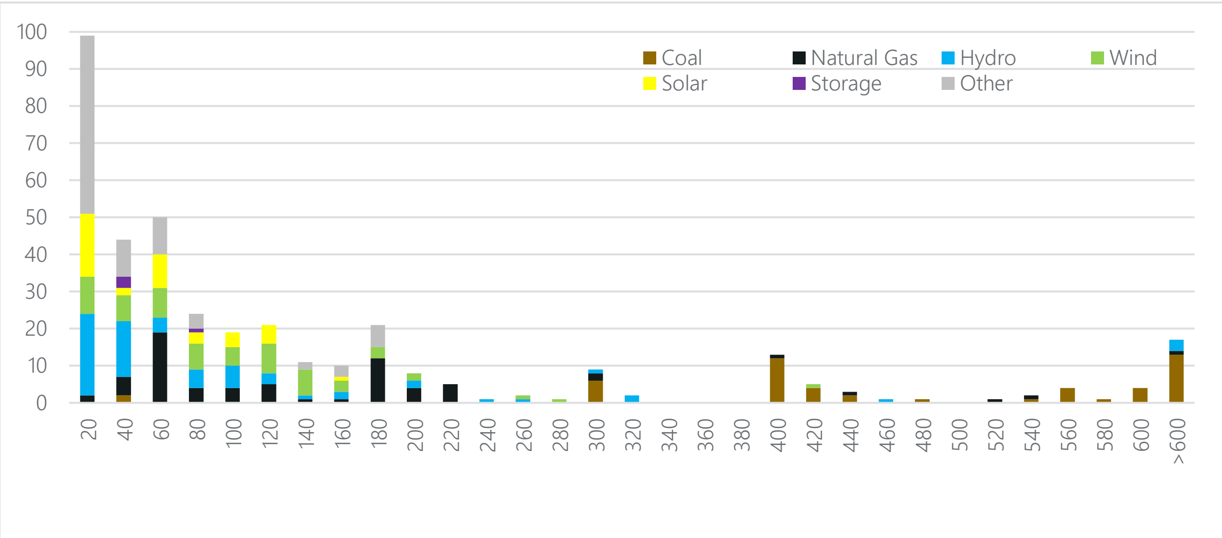
AEMO recognises that other Generators would need to alter their plant control systems, some substantially, to operate in a mode where frequency response was delivered, and not defeated, once frequency was outside a specified narrow frequency response deadband.

A few generating systems may not be capable of providing PFR because the plant modification required is technically or economically infeasible. A mechanism is identified in this proposal to assess the technical ability of generation to meet the proposed frequency response requirements, and exclude generating systems from the requirements of this proposed rule where they cannot reasonably be modified to provide PFR. AEMO expects that only a small number of generating systems would fall into this category.

Optimal providers of PFR

Figure 6 shows a histogram of generating unit size in the NEM. This indicates that the largest generating systems in the NEM, namely, those over 200 MW of installed capacity, are typically large synchronous generating systems.

Figure 6 Histogram of Generating System Sizes in the NEM



The largest generating plants in the NEM have the greatest aggregate capability to deliver PFR to support the control of power system frequency, and increase the resilience of the power system to disturbances. Their unit size means they are capable of providing a larger absolute MW response to a disturbance. As they are typically online, they can also provide a response for the greatest number of hours a year.

The proposed rule, however, is technology neutral, and requires that all technically capable scheduled and semi-scheduled generation should be required to contribute to power system frequency control, essentially as a condition of connection to the power system. This includes variable renewables such as wind and PV.

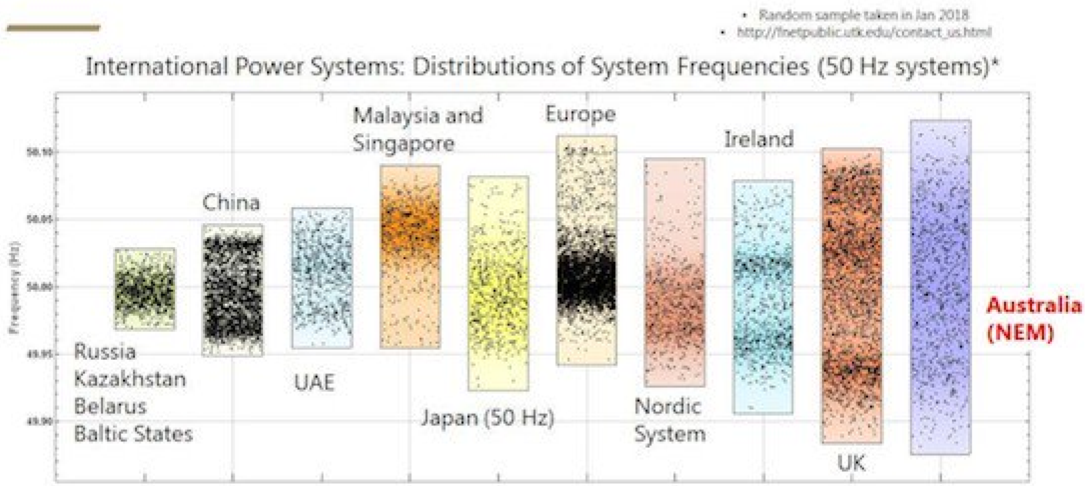
If all capable scheduled and semi-scheduled generation in the NEM were required to provide PFR in accordance with AEMO's specifications, all the objectives of this rule would be met with lowest impact on the operation of each affected Generator.

6. HOW THE NEM COMPARES TO OTHER POWER SYSTEMS

This section highlights that the NEM is now an international outlier, both in terms of frequency outcomes at the system level, and also in terms of the requirements on generation to support effective control of power system frequency.

Figure 7 compares Australia's frequency performance under normal operating conditions as against other 50 Hz power systems, showing that the NEM's level of frequency variation is wider that other comparable systems, both smaller and larger than the NEM[38].

Figure 7 Comparative frequency performance across various power systems



This outcome is primarily a function of the wide frequency response deadband settings now being applied in the NEM, or associated changes made in some cases to plant load controllers to reduce or defeat the sustained delivery of PFR from generation, particularly within the NOFB under normal operating conditions.

The challenges posed both by the transformation of a power system dominated by synchronous generation to one with an increasing level of asynchronous generation, and by changes to the delivery of PFR is being experienced by many power system operators around the globe to varying degrees.

[38] Source: https://www.linkedin.com/pulse/system-frequency-what-doing-why-does-matter-bruce-miller/.

Management of the transition requires ongoing review of operational practices, including PFR requirements, to maintain power system performance.

A key point of difference between the NEM and other power systems is that the regulatory frameworks and market bodies do not treat the provision of PFR under normal operating conditions separately from the provision of PFR following disturbances. It is simply PFR.

A wide range of different arrangements are used to manage the provision of PFR, and associated response reserves. Table 4 compares the responses from various power system regulators and operators around the globe[39]:

Table 4 Arrangements for management of PFR and response reserves

Jurisdiction	Providers of PFR	Threshold	Frequency response of generation	Procurement of response reserves
NEM	Generation	5 MW	Market	Market, with voluntary offering
Western Australia	All scheduled generation[40]	10 MW	Mandatory	Market, with mandatory offering from largest portfolio
Brazil	Thermal & Hydro Generation	30 MW	Mandatory	Not managed
California	Generation	20 MW	Assessing moving to market	Market
Great Britain	Generation & Load	100 MW[41]	Mandatory	Market, with mandatory offering
Finland	Synchronous & Wind Generation & Load	10 MW[42]	Market	Market
Ireland	Synchronous & Wind Generation	2 MW	Mandatory	Market
New Zealand	Generation & Load	30 MW[43]	Market	Market
Ontario	Generation	20 MW	Contracted	Market
Singapore	Generation & Load	10 MW	Mandatory	Market
Spain	Generation	All	Mandatory	Mandatory headroom

[39] Source: Ciaran Roberts, Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory, Review of International Grid Codes, February 2018. Available at: https://certs.lbl.gov/sites/default/files/international_grid_codes_lbnl-2001104.pdf. Much of the balance of Section 6 has been derived from this source.

[40] Expansion of requirement to non-synchronous under consideration presently.

[41] For National Grid. The thresholds elsewhere are 10 MW for Scottish Hydro Electricity Transmission and 30 MW for Scottish Power. See pages 206-207. AEMC - Draft Report - Frequency Frameworks Review. Available at https://www.aemc.gov.au/sites/default/files/2018-03/Draft%20report.pdf.

[42] Noting that FinGrid has the power to require specific responses during disturbances from all generation above 0.5 MW. See Specifications for the Operational Performance of Power Generating Facilities VJV2013. Available at: https://www.fingrid.fi/globalassets/dokumentit/en/customers/grid-connection/specifications-for-the-operational-performance-of-power-generating-facilities-vjv2013.pdf.

[43] Clause 8.21 of the Electricity Industry Participation Code 2010. Available at: https://www.ea.govt.nz/code-and-compliance/the-code/part-8-common-quality/

Switzerland	Generation	All	Market	Market
Texas	Generation and Load, except Nuclear and older Wind	10 MW	Mandatory	Market

The arrangements for management of PFR in selected jurisdictions is considered in more detail below.

6.1 United States

The North American Electric Reliability Corporation (**NERC**) makes reliability standards that the Federal Energy Regulatory Commission (**FERC**) approves. FERC has mandated the provision of PFR without compensation from all new generation and existing generation seeking to augment its capacity from 15 February 2018.[44] Balancing authorities in the United States may seek approval for regional standards. The balance of Section 6.1 considers the situation in two of those regions.

6.1.1 Texas

The Electric Reliability Council of Texas (**ERCOT**) operates the Texas Interconnection and has applied a regional standard for the provision of PFR since 2014, which requires PFR through mandated governor deadbands and droop settings. These requirements were updated in 2018 to require all new generation to enable PFR capability as a condition of connection[45].

PFR is expected within 1.5 seconds, with full response in 16 seconds, to be sustained for 1 hour.

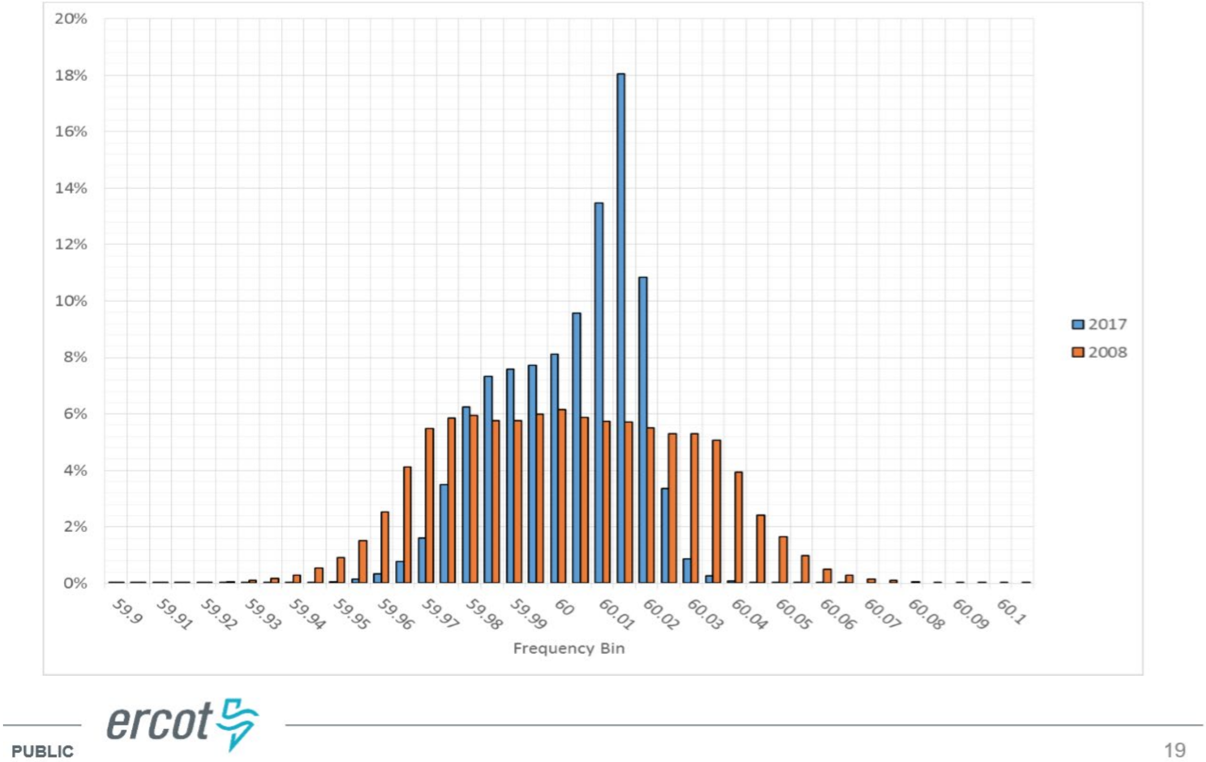
ERCOT has published information on the improvement to its power system as a result of these measures. Figure 8 provides a snapshot of the improvement in power system frequency in Texas from 2008 to 2017[46].

[44] Order No. 842 (RM16-6-000), February 15, 2018. Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response (Final Rule). Available at: https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf.

[45] See pages 211-213, AEMC Draft Report - Frequency Control Frameworks Review.

[46] ERCOT, Presentation, Demonstration of PFR Improvement, September 2017. Available at: https://www.pjm.com/-/media/committees-groups/task-forces/pfrstf/20171009/20171009-item-04-ercot-frequency-response-improvements.ashx.

Figure 8 Comparison between 2008 & 2017 Frequency Profile



6.1.2 California

The California Independent System Operator (**CAISO**) procures PFR through a market but is in the process of redesigning its approach to include procurement from other authorities in the Western Interconnection. It will also specify a maximum allowable deadband of $\pm$0.036 Hz and droop of 4% for all thermal generation and 5% for other generation and will prohibit the withdrawal of an initial response, except under operational constraints, such as ambient temperature limitations, outages of mechanical equipment, or regulatory considerations.

CAISO is proposing to explore a market-based mechanism to compensate providers of PFR.[47]

6.2 Europe

European power systems are regulated by the European Network of Transmission System Operators for Electricity (**ENTSO-E**). A harmonised grid connection code focuses more on the performance requirements of PFR rather than its procurement, which is left for each transmission system operator to determine.

6.2.1 Great Britain

PFR reserves are procured by National Grid through a market, in which operators of generation must submit bids for capacity reservation, however, agreements are entered into between National Grid and operators.

National Grid also operates a 'firm frequency response' market, which is open to generation and providers of interruptible load of more than 1 MW. PFR in this market must be provided within 10 seconds and be sustainable for 30 seconds.

[47] See also FERC, Order on Proposed Tariff Revisions, issued 16 September 2016. Available at: http://www.caiso.com/Documents/Sep16_2016_Order_ProposedTariffRevisions_ConditionallyAcceptingFrequencyResponse_ER16-1483.pdf.

More recently, National Grid has procured an 'enhanced frequency response' from storage providers who can provide PFR with the following characteristics:

- Maximum deadband of either $\pm$0.050 Hz (Service 1) or $\pm$0.015 Hz (Service 2).
- Ability to detect a frequency deviation within 500ms and to deliver contracted response within 1 second.
- Ability to sustain response for 15 minutes.

6.2.2 Finland

Fingrid, the operator of the Finnish power system, requires mandatory PFR capabilities with adjustable droop and deadband ranges. PFR is procured through two markets, one for PFR under normal conditions, and one for PFR following disturbances. The market for PFR following disturbances is annual and hourly.

6.2.3 Ireland

EirGrid, the operator of the Irish power system, requires PFR that meets specified droop and deadband requirements. Generation must operate continuously in frequency sensitive mode.

Traditionally, PFR reserves have been procured through bilateral contracts, however, EirGrid is developing two new markets for frequency control reserves, one of which is for a 'fast frequency response'. EirGrid also awards long-term 'primary operating reserve' contracts through an auction.

6.2.4 Spain

Red Electrica de Espana, the operator of the Spanish power system, mandates the provision of PFR without remuneration. All generating units must reserve 1.5% of their capacity to provide PFR.

6.2.5 Switzerland

Swissgrid, the operator of the Swiss power system, requires PFR capabilities and specifies adjustable droop and deadband ranges. PFR is procured through a common market that serves Austria, Switzerland, The Netherlands, Belgium, France and Germany. The market hosts weekly auctions for one symmetrical product (capable of increasing or decreasing generation/load) of at least 1 MW.

6.3 New Zealand

New Zealand operates a market for reserve to manage frequency in response to an event that takes frequency outside of a 'normal band'. Inside the normal band generators have traditionally provided PFR, however, over time this response has been withdrawn as there is no technical requirement.[48]

In response to the challenges New Zealand faces, the Electricity Authority of New Zealand recently published a decision paper[49] discussing a plan for a proposed capability market involving a tender-based procurement for PFR within the NOFB.

[48] See Normal Frequency Management Strategic Review Information Paper, March 2017. Available at: https://www.ea.govt.nz/development/work-programme/risk-management/normal-frequency-management-strategic-review/consultations.

[49] See Normal Frequency Management Decision Paper, 18 September 2018. Available at: https://www.ea.govt.nz/dmsdocument/24082-decision-paper-normal-frequency-management

6.4 Ontario

The Ontario Independent Electricity System Operator (**IESO**) mandates a maximum deadband, adjustable droop range and rate of delivery of PFR. All generating systems must regulate speed with an average droop based on maximum active power, adjustable between 3% and 7%, and set at 4% unless otherwise specified.

6.5 Brazil

Brazil's system operator, Operador Nacional do Sistema Eletrico (**ONS**), mandates the provision of PFR from thermal and hydro generation, although there is no requirement for reserve capacity. Capability is verified prior to connection and the provision of PFR is not remunerated.

6.6 Singapore

The Singapore Energy Market Authority requires PFR from all generation. It operates a market for PFR reserves in Singapore, in which both generation and providers of interruptible load may participate, although the contribution from interruptible load to the total system reserve requirement for PFR is capped at 20%.

The Singaporean market is unique in that it caps the cost of procurement of reserves to operators of generation as a function of their output and their probability of tripping, thus incentivising them to minimise tripping.

6.7 Summary of technical requirements for PFR in selected jurisdictions

The technical requirements imposed on owners of generation vary between the jurisdictions considered. Table 5 highlights some of the key technical performance requirements imposed on generation.

Table 5 Comparison of Technical Requirements for the provision of PFR in Various Jurisdictions

Jurisdiction	Maximum Deadband (±Hz)	Droop
NEM	0.15 for generators who chose to participate in FCAS markets. 1.0 Hz for other generation	2% - 10% for new generation connections.
Western Australia	0.025	4%
Brazil	0.040	2% - 8%
Finland	0.100[50]	2% - 12%
Great Britain	0.015[51]	3% - 5%
Ireland	0.015	3% - 5% for synchronous generation 4%[52] for wind generation
New Zealand	None specified	0% - 7%[53]
Ontario	0.036	4%[54]
Singapore	0.050	3% - 5%

[50] Market participation requirement.
[51] Except for steam units within a CCGT module.
[52] Adjustable to between 2% - 10%.
[53] This is a capability only, not an ongoing requirement.
[54] Adjustable to between 2% - 7%.

Jurisdiction	Maximum Deadband (±Hz)	Droop
Spain	0	As instructed by ISO
Switzerland	0.010[55]	2% - 12%
Texas	0.034 for steam/hydro with mechanical governor 0.017 for all other generation	4% for combustion 5% for all other generation

This review confirms that the NEM's current design of neither incentivising, nor mandating, any PFR in response to frequency deviations under normal operating conditions, within a band of ±0.150 Hz, and relying entirely on the use of secondary frequency control via AGC is unique for the ongoing control of power system frequency.

7. COMPLEMENTARY ACTIONS BY AEMO

AEMO continues to undertake or investigate several actions alongside this rule change proposal that are material to frequency control, as detailed in the remainder of Section 7.

While these actions contribute to improvement in frequency control and response to disturbances, they are not sufficient on their own to maintain suitable levels of power system resilience or stability of frequency control as the grid transforms. Resilience and effective control will only be achieved when the level of primary frequency control in the NEM has returned to historical levels, with much tighter settings applied.

7.1 Reviewing Regulation FCAS volumes

Commencing in March 2019, AEMO adopted a policy of increasing base volumes of Regulation FCAS procured for the mainland in small increments as required after approximately four-weekly reviews. These reviews will occur on an ongoing basis, and may result in increases up to an initial maximum volume of 250 MW[56]. Monthly updates on the results of these changes now are being published on AEMO's website[57].

Regulation FCAS is currently the only tool available to AEMO to control frequency under normal operating conditions and increasing Regulation FCAS is an attempt to improve frequency control to the point where AEMO can again meet or exceed the minimal requirements of the FOS under normal operating conditions.

Regulation FCAS is centrally controlled by AEMO through AGC and serves several purposes, including management of forecast errors, controlling time error, and slow correction of power system frequency. The design and purposes of AGC mean that it is not suitable as the sole mechanism for correcting ongoing rapid movements in frequency within the NOFB, as discussed in Section 3.2.1.

Prior to 22 March 2019, the base volumes of Regulation FCAS procured were 130 MW Regulation Raise and 120 Regulation Lower. Table 6 shows the increases made since that date:

Table 6 Increases in base Regulation FCAS since 22 March 2019

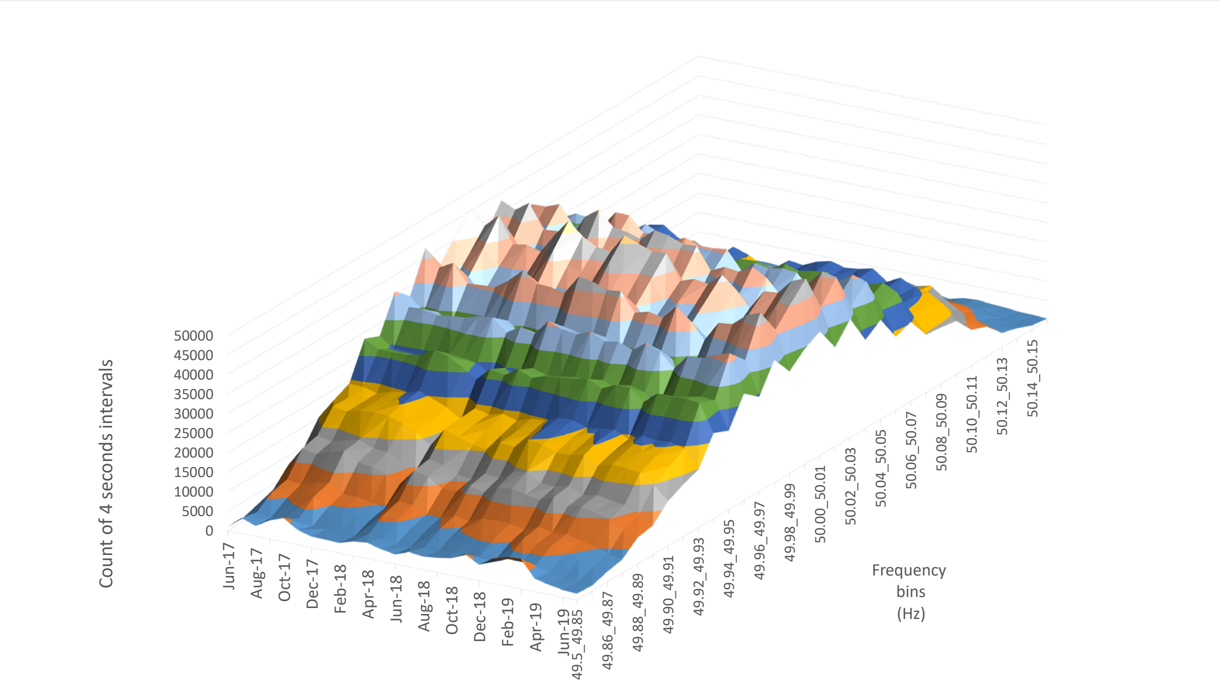
Date	Increase	Percentage Increase	Total Base Volume
22 March 2019	50 MW	~ 38%	Regulation Raise 180 MW Regulation Lower 170 MW
23 April 2019	20 MW	~ 53%	Regulation Raise 200 MW Regulation Lower 190 MW

55 Market participation requirement.
56 See Regulation FCAS Changes, March 2019. Available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/Regulation-FCAS-factsheet.pdf
57 See Frequency and Time Deviation Monitoring, April 2019. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring

23 May 2019	20 MW	~ 69%	Regulation Raise 220 MW Regulation Lower 210 MW

The outcomes of these increases are shown in Figure 9.

Figure 9 Frequency distribution within the NOFB for the last 12 months



The increase in secondary control reserves has not narrowed the distribution of frequency, or improved the stability of control of frequency within the NOFB. At best, the chart indicates that, perhaps, power system frequency is not exiting the NOFB as frequently or remaining outside the NOFB as long. However, there is insufficient data as yet to conclude whether any real benefits within the NOFB have been gained or that they are sustainable.

An aggregate increase of around 70% in the base volume of Regulation FCAS procured[58] has only reversed, possibly, 12 months of decline in keeping power system frequency to within the NOFB. It has done nothing to address the decline in the stability of frequency control close to 50 Hz.

7.2 Regional allocation of Regulation FCAS

AEMO is considering the implementation of a maximum cap on the volume of Regulation FCAS that can be procured from each region, which is intended to ensure geographic diversity in the delivery of this response.

As Regulation FCAS is continuously utilised during normal operation of the power system, its over-allocation to any one region will have an ongoing impact on network flows in and around that region. Geographic dispersal will reduce the impact of its ongoing utilisation on network flows, particularly interconnectors, resulting in more stable operation of the power system.

[58] Factsheets available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

7.3 Review and regional allocation of Contingency FCAS volumes

AEMO is reviewing the volumes of Contingency FCAS being procured. The key factors that may affect volumes are the assumed load relief, and the response of distributed energy resources (DER) to disturbances.

AEMO has recently completed an engineering review on the contribution from demand to arresting power system frequency disturbances, known as 'load relief', which suggests this factor is now significantly lower than historically assumed. This change, which will drive increase in Contingency FCAS needs, will be implemented from Q3 2019. Over 1,000 constraint equations are being changed to achieve this outcome. A review of the response of DER to disturbances is ongoing.

AEMO is also considering whether there is a need for geographic diversity in the sources of Contingency FCAS, similar to the approach being considered for Regulation FCAS.

7.4 Further review of AGC performance

As noted in Section 2.4.1, AEMO is further reviewing AGC performance again after undergoing a tuning last year and expects this to be completed by the end of 2019.

The purpose of this review is to ensure optimal usage of the Regulation FCAS procured.

7.5 Disincentives in the MASS

The way AEMO measures the provision of Contingency FCAS, as specified in the MASS, incentivises the delayed delivery of PFR until power system frequency crosses the edge of the NOFB.

It is not in the interests of power system performance to encourage Generators to delay or withhold delivery of PFR following a disturbance because an earlier delivery will reduce the frequency deviation that occurs following a contingency event.

AEMO is addressing this issue in a separate review of the MASS outside this rule change proposal.

7.6 EFCS and Protected events

AEMO has undertaken a review of some key emergency control schemes in the NEM, and has submitted the first Protected Event for the loss of the Heywood interconnector (for which $5m has been approved by the Reliability Panel to address the risks AEMO identified in its review).

7.7 Inverter Standards for DER

AEMO has submitted a formal proposal to Standards Australia to review AS/NZS 4777.2 Grid connection of energy systems via Inverters: Inverter Requirements. The update proposed by AEMO will align DER performance with both utility-scale plant capabilities (where feasible) and with best practice international standards.

8. FREQUENCY OPERATING STANDARD

A potential solution to arrest the deterioration of frequency performance in the NEM is to make the frequency requirements in the FOS more stringent. The FOS is a standard that the power system and thereby AEMO is expected to meet, but it can only do so using the limited range of tools at its disposal. Notably, there is no specific requirement for Generators to assist AEMO in meeting the FOS requirements.

The NER broadly separates contingency events into credible, non-credible and, under some conditions, yet to be declared, protected. The FOS specifies minimum acceptable power system frequency outcomes for each type of event.

Furthermore, as noted in Section 4.1.2, AEMO is becoming increasingly unable to meet certain aspects of the FOS requirements already, therefore, amending the FOS to tighten the requirements on AEMO will only cause AEMO to breach them more often until new tools become available.

The frequency bands specified in the FOS, along with the settings of UFLS and OFGS, imply that their use is an acceptable outcome for any contingency event that is beyond a credible contingency event. These arrangements do not ensure any level of power system performance above these minimum outcomes, or any suggestion that this might be desirable or appropriate.

Modifying the FOS would not, by itself, either increase power system resilience or increase the effective control of power system frequency under normal conditions, and AEMO does not consider this to be an appropriate response to the problem detailed in this document. It would do nothing by itself to align NEM control practices with those used internationally.

The proposed rule would continue to ensure that the requirements of the FOS were met. It would also ensure that it would take bigger disturbances than those experienced to date to result in the most severe acceptable outcomes, those involving UFLS or OFGS.

9. STAKEHOLDER ENGAGEMENT

Prior to submission of this rule change proposal, AEMO met with all the Generators with large generation portfolios in the NEM, and some with smaller generation, to discuss the issues underlying this rule change proposal and AEMO's proposal for a mandatory PFR requirement.

These Generators covered all generation technologies currently used in the NEM. AEMO also met with large consumers and small consumer representatives as well as industry body representatives. The discussions also covered the subject matter of AEMO's separate rule change proposal intended to remove identified disincentives to the provision of PFR within the NOFB.

The regulatory solution AEMO canvassed with stakeholders was a requirement to provide PFR once system frequency reached the outer limits of the NOFB. For the reasons mentioned in Sections 1 and 2.4.1, AEMO has since determined that a different approach is necessary, and AEMO acknowledges that some stakeholders may have had different views if asked for feedback on AEMO's current proposal. Nevertheless, much of the feedback received remains relevant.

9.1.1 Generators

The Generators provided a range of responses on the causes and consequences of the decline in PFR, as well as the potential solutions:

Concern with current state of power system

- Some Generators operating large synchronous generating units expressed concern about the level of ongoing frequency changes now observed on the power system. They noted it was difficult to quantify the exact costs and risks of these changes, but that the level of frequency variation was making stable operation of their plant more difficult. Some reported increased difficulty and delays in synchronising their generating units.
- One expressed concerns about the increased long-term risk of asset failures.
- Some were surprised at AEMO's focus on PFR as a concern arising from the 25 August 2018 event as they considered that the power system's response was broadly as expected, and that other matters

raised in the AEMO Incident Report were of greater importance. In other words, UFLS and OFGS operated as designed, and so there was no need for change.

Potential for overlap with Contingency FCAS

- Some raised concerns around the overlap of any obligation to provide PFR with Contingency FCAS markets. If a mandatory PFR band were to be set outside frequency bands where Contingency FCAS markets exist, this concern would be partially addressed.
- Some raised questions around the potential impacts on compliance with Contingency FCAS market offers, or reduced ability to offer Contingency FCAS.
- One questioned whether AEMO might reduce the volumes of Contingency FCAS purchased if it knew that additional PFR might be delivered outside of those markets.

First mover disadvantage as a disincentive to provide PFR

- Some were supportive of a mandatory PFR requirement, particularly if the performance expected from all Generators was clear, as the current regulatory and market arrangements were seen as convoluted, and hard to understand and translate into actual performance requirements.

Miscellaneous barriers to provision of PFR

- Some raised concerns around compliance with their performance standards and modelling requirements for their generation.
- Some Generators with wind generation advised their plant was fundamentally incapable of providing PFR, and that they would seek to be exempted from any requirement to provide it. One advised that their own plant was not negatively affected by current power system frequency performance, and they did not believe a case had been made as to why it should be improved.

Ease of modifying plant to provide PFR

- Some Generators with synchronous generating units advised that, as a matter of practicality, they expected it would be relatively straightforward to modify relevant control system settings, such as frequency response deadbands, or whether the unit was operated in frequency response mode.
- One wished to seek advice from its equipment manufacturer before making any changes.

9.1.2 Consumers

Meetings were also held with large and small customer representatives to brief them and seek feedback on the proposed changes.

- Major industrial load customers stressed the undesirability of supply interruption, except where no other options were available.
- One noted that the resilience of their loads to supply interruption has reduced since they were originally commissioned.
- One major customer advised they were participating in some of the FCAS markets, which provided a valuable income stream and they were assessing their ability to participate in more FCAS markets.

9.1.3 Others

- Industry representatives largely reflected the comments of their members, namely that Generators should be paid to provide more PFR if, in fact, that was what the power system needed.

- Small customer representatives were focussed on the cost impacts of these proposals. They understood that the proposal (as it then stood) would not directly alter total market costs for FCAS but could alter the distribution of how these costs were recovered.

10. URGENCY

AEMO recognises that this proposal represents a significant change to the NEM regulatory framework that has been in place since 2001, but it is also necessary to acknowledge that the power system assumptions on which that framework was based have fundamentally changed. AEMO requests the AEMC to progress this proposed rule in the shortest reasonable timeframe, balancing the requirement for appropriate consultation with the potential consequences of the ongoing lack of effective frequency control in normal operating conditions.

10.1 General observations

Frequency performance continues to decline. AEMO considers it is imperative that the frequency stability, resilience and predictability of the response of the power system is increased. A 'do-nothing' approach is not appropriate and will result in further ongoing deterioration of power system frequency performance.

This will occur as generation is connected to the power system with no arrangements to ensure it is operated in a frequency responsive manner, existing, frequency-responsive generation is displaced or retired, generation that is currently frequency-responsive continues to be made less so by its operators, and distributed generation with unknown or poorly specified disturbance response continues to be connected.

The events of 25 August 2018 demonstrate that the decline in PFR has already reached a point where the power system is not as resilient to contingency events of a magnitude only around 15% greater than the largest credible contingency event. It is noted that this event occurred under relatively benign system conditions, with the majority of system demand being met by synchronous generation.

Power system frequency performance under normal operating conditions has continued to deteriorate even in the relatively short elapsed time period since this event.

Conditions on the power system continue to change at an unprecedented rate, in large part due to the very rapid rate of new generation development across the NEM. Given both the rapid rate of connection of new generation in the NEM and the ongoing decline in frequency performance, it is AEMO's view that an urgent response is now required.

Recent work by AEMO assessing the potential need for and design of Emergency Frequency Control Schemes has highlighted the difficulties of doing this, in the absence of simple predictability around the expected response of generation to major disturbances.

The balance of Section 10 explains why any delay in making the proposed rule will only increase the threat to the effective operation, safety, security and reliability of the power system.

10.2 Assumptions No Longer Valid

The 25 August 2018 event demonstrates that the timeframes for the existing regulatory arrangements to address the issue of poor frequency performance are no longer appropriate. A relatively unchanging mix of generation and slow rate of new connections in the past meant that AEMO could learn from power system incidents, both within the NEM and internationally, to improve its management of the power system. In the past, both the performance of different types of generation following a contingency event (credible or not), and the overall performance of the power system could be taken as reasonably accurate predictors of future performance.

Today, the increase in the range of generation technologies connecting to the power system and the sheer volume of new connections is negating the usefulness of historical event analyses in predicting future outcomes, or indeed, assisting AEMO in being able to take pre-emptive action to minimise the risk of small incidents becoming larger incidents. AEMO's ability to take on board the learnings of other system operators is limited by the fact that NEM power system frequency performance is not comparable or consistent with international norms.

Hence, and as discussed in Section 4.1.3, each contingency event is increasingly likely to result in unexpected or different outcomes to those seen previously, limiting AEMO's ability to take pre-emptive action to prevent those outcomes, including load or generation shedding and even cascading failures across entire networks.

10.3 Increased Probability of Load or Generation Shedding Events

The lack of resilience in the NEM to major disturbance events is increasing the probability that UFLS or OFGS will occur following any non-credible contingency event. More stable frequency control itself will increase power system resilience, and in turn, minimise the risk that load or generation shedding will be the only available means of responding to changes in frequency following significant disturbances.

AEMO believes that UFLS and OFGS should be reserved for managing only the most extreme events where no other options are available. AEMO do not believe it is appropriate that they should be used where there is response capability available from existing generation that would minimise or prevent the use of these emergency, last resort options.

AEMO also note that the effectiveness and predictability of UFLS as an emergency response is now less certain in some regions of the NEM, under some operating conditions, due to the rapid and ongoing increase in distributed PV generation. This strengthens the case for taking all reasonable steps to minimise the need for relying on those schemes to operate as intended.

10.4 Rate of New Generation Connections

AEMO reported a large increase in new generation from Q4 2017 to Q4 in 2018 in its Quarterly Energy Dynamics Q4 2018 publication. Around 835 MW of new generation commenced operation in Q4 2018 alone[59].

Delaying the implementation of a new rule requiring PFR will result in a significant volume of new generation being connected without any requirement to operate in frequency response mode except when it is dispatched to provide a market ancillary service.

A substantial proportion of new generation is solar and wind, and this is projected to continue. Figure 10 shows a breakdown of the committed and proposed generation in the NEM, current to 30 April 2019[60].

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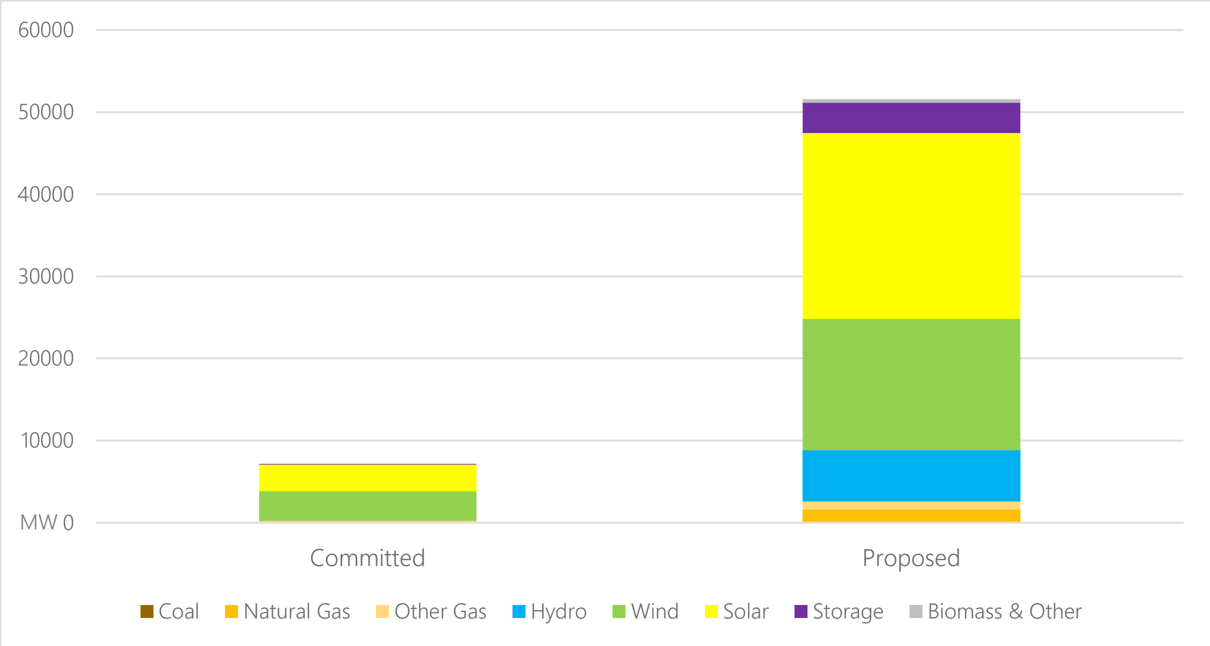
[59] Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q4-2018.pdf.

[60] Source: AEMO's Generation Information Page. Available: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 10 Breakdown of Committed and Proposed Generation in the NEM



As noted in Section 4.1.1, both solar and wind generation are subject to the vagaries of the weather, which means that their output can be volatile, unless coupled with significant battery storage technology to smooth output. As time goes on, the proportion of solar and wind generation in the NEM will rise significantly, forcing older, synchronous plant to retire.

10.5 Five-Minute Settlement

The *National Electricity Amendment (Five Minute Settlement) Rule* 2017 No. 15 commences on 1 July 2021. If broad-based PFR is not available by that date, AEMO expects it will be significantly more difficult to maintain power system frequency to meet the requirements of the FOS both under normal operating conditions and following contingency events.

When operating to a five-minute settlement timeframe, Generators will have a shorter timeframe to increase, or reduce, output in response to known high or low spot prices, respectively. This has the potential to incentivise more rapid changes in output which, in turn, has the potential to cause large changes in power system frequency if rapid generation output changes are not automatically constrained or limited by PFR. The potentially more volatile market conditions are likely to be mirrored in the FCAS markets also; that is, the allocation of FCAS from the 5-minute markets may become more volatile and difficult to predict with confidence.

10.6 Power system needs are paramount

Increasing the frequency stability and the resilience of the power system cannot be delayed until a new market mechanism for PFR is debated, designed, trialled and implemented. It would not be prudent to assume that any mechanism that continues or builds upon the design assumptions of the current FCAS arrangements will ultimately be successful. In contrast, the approach proposed in this rule change is entirely consistent with long standing and demonstrably effective industry practice.

AEMO stated in its submission to the AEMC during the Frequency Control Frameworks Review that 'while a form of payment mechanism would be the most effective solution to the procurement of [PFR] in the longer-term, the design of any mechanism must build on the underlying technical needs of the system'[61]. What that means is that the underlying physics of the power system do not yield to economics.

The FCAS markets as they currently exist are simply not capable of managing the full range of challenges facing the power system in the absence of broad-based PFR. It is worth recalling that, on 25 August 2018, Contingency Lower FCAS had been purchased through the spot market from outside QLD, but it was of no use when QLD needed it because QLD was islanded from the rest of the NEM. The response that was ultimately delivered in QLD was not co-ordinated via the market arrangements, but relied on legacy, or uncoordinated and unmanaged frequency response.

AEMO has previously advised the AEMC that the most effective PFR would be that sourced within the vicinity of the cause of any given frequency deviation.[62] Broad based obligations for provision of PFR would address this concern, among others.

11. IMPLEMENTATION OF CHANGE

Implementation of the PFR requirement AEMO proposes would need to be carefully coordinated and consulted with affected generators, to regain a meaningful level of control in a prompt manner, without first-movers taking on greater risk in providing PFR.

AEMO proposes that all Generators with scheduled and semi-scheduled generating systems that have a nameplate rating of 200 MW or more would be the first to be required to meet the new requirements for PFR. The remaining (technically capable) scheduled and semi-scheduled generating systems would have to adjust their plant after this first tranche is completed.

Based on analysis of registered NEM generating capacity, the staged implementation is expected to cover the approximate volumes of generation specified in Table 7.

Table 7 Implementation Stages

	Scheduled					Semi-Scheduled				
	QLD	NSW	VIC	SA	TAS	QLD	NSW	VIC	SA	TAS
Tranche 1	11,507	15,293	9,328	2,505	1,349	-	270	420	238	-
Tranche 2	633	450	737	768	1,434	1,180	1,518	1,571	1,638	168

12. PROPOSED RULE

12.1 Description of the proposed rule

A draft of the proposed rule is attached in Appendix A.

The proposed rule will require greater provision of PFR to increase the power system's resilience, and provide effective control of power system on an ongoing basis.

12.1.1 Obligation on Generators to provide PFR

A new rule will require Generators with capable scheduled and semi-scheduled generating systems to operate their generating systems in accordance with the Primary Frequency Response Requirements (**PFRR**), an instrument under the NER.

[61] See pages 36, 85 & 118, AEMC Final Report.

[62] AEMO Advice to AEMC dated 5 March 2018. Available at: https://www.aemc.gov.au/sites/default/files/2018-03/Advice%20from%20AEMO%20-%20Primary%20frequency%20control.PDF.

12.1.2 Primary Frequency Response Requirements

AEMO will be required to publish and update a PFRR in accordance with the rules consultation procedures. Transitional rules will provide for AEMO to make the initial PFRR.

The PFRR would specify the requirements to be met when providing PFR, including:

- The frequency response band outside of which PFR is required will be set at a small value, well within the NOFB. As explained in this proposal, this will be a prudent level necessary to restore effective control of power system frequency under normal operating conditions, and re-align the NEM with comparable power system practice worldwide.
- AEMO proposes that the frequency response band is set at +/- 0.015 Hz, based on advice received from AEMO's expert consultant.
- Generators would not be required to reserve headroom to provide PFR but where they were safely and stably capable of providing PFR, based on available response headroom, they would be expected to do so.
- There would be no requirement to sustain PFR for a specified time, and plant would not be expected to respond beyond its primary energy limits, above maximum output, or below minimum stable operating levels.
- However, generators should not unnecessarily limit or defeat PFR, or unnecessarily withdraw PFR.

The PFRR would specify the grounds on which exemption from, or modified application of, these requirements could be sought by Generators where it is not feasible for their generating systems to comply. Generating systems that could reasonably be modified to comply (for example, through adjustment of control settings) would not be exempt.

12.1.3 Removal of disincentives

As previously noted, AEMO has submitted a separate rule change proposal to amend clauses 3.15.6A, 4.9.4, 4.9.8 and S5.2.5.11 of the NER to remove perceived regulatory obstacles identified by Generators as reasons for limiting or withdrawing provision of PFR from their generating systems. If that rule is not made prior to the AEMC's final determination on this proposal then, as a minimum, the changes to clauses 4.9.4, 4.9.8 and S5.2.511 will be necessary to support a mandatory PFR requirement. Accordingly, they are included in the proposed rule for completeness.

12.1.4 Compensation for necessary adjustment costs

The proposed rule contemplates that Generators would be able to recover any material costs they reasonably incur in adjusting their plant and control systems to comply with the PFRR.

AEMO proposes that only substantive claims for compensation should be assessed and, if appropriate, paid, but has not specified a threshold amount for compensation to be payable. AEMO expects the AEMC's consultation will assist in the determination of an appropriate materiality threshold.

12.2 Primary Frequency Response Requirements

The rationale for the requirements for the delivery of PFR in the PFRR are as follows:

12.2.1 Deadband

A generating system must be operated such that it will deliver PFR outside a specified frequency response deadband. An absolute zero PFR deadband for all generation would likely be unrealisable, and impractical because mechanical performance and frequency measurement accuracy will not be perfect. .

This rule change proposes that the allowable deadband is ± 0.015 Hz. This would be applicable to control of frequency response provided by both machine speed governors, and from plant load control systems which may then act on the setpoints of machine speed governors.

In developing this rule change, a range of potential PFR deadbands were considered between near-zero and the frequency band specified for a mainland 'Generation Event' or 'Load Event', as specified in the FOS as ±0.500 Hz.

AEMO acknowledges that the proposed frequency response deadband is smaller than that currently used by a number of NEM generators, and is at the narrow end of the range of values considered. The international expert advice AEMO received on NEM frequency control practices was a key factor in determining this narrow deadband. Deadbands as low as ±0.010 Hz are specified in some grid codes.

The remainder of this Section 12.2.1 assesses the likely outcomes for frequency control and FCAS markets of different deadband scenarios – the narrow band proposed, a very wide band at ±0.5 Hz, or a wide band aligned with the NOFB.

Outcomes with a narrow frequency response deadband

(a) Achieving effective control and resilience

A very narrow deadband specification would result in the widest ongoing provision of PFR across the NEM. All generation would be continually responding to deviations in frequency under normal operating conditions. The total response burden of correcting a MW imbalance, whether small or large, would be distributed amongst the largest possible number of parties, minimising the operational impact on any individual generating system.

For such a design to be most effective, unit MW setpoints and energy market dispatch targets would need to be considered as effective at 50 Hz only. All generation would be continuously moving slightly away from remotely transmitted dispatch targets to provide PFR and resist frequency change away from 50 Hz.

To fully support such an arrangement, it would be necessary for plant load controllers to implement a form of frequency bias on the externally received load setpoints, whether these were transmitted remotely from AEMO, or determined by internal dispatch and control systems managed by the generation operators.

The use of a near-zero deadband would, consistent with international practice, remove any practical distinction between frequency control under normal conditions and frequency control following a disturbance. At present, the NOFB is defined as the boundary between these two different frequency conditions. With a near-zero deadband specification, the same control mechanisms would be providing PFR in response to any level of frequency change:

- Under normal operating conditions, this arrangement results in the most stable control of frequency. It would reduce the amplitude of the observed ongoing oscillations in NEM frequency to the lowest practicable level. Care would be needed in the control tuning of both speed governors and plant load control systems to ensure that individual plants remained stable while responding to ongoing frequency changes, and that interactions with other control systems such as power system stabilisers were avoided.
- At the same time, the arrangement maximises the resilience of the NEM to frequency disturbances. The frequency deviation that results from any given event or operating condition would be as small as reasonably possible, a prudent engineering practice that provides the best opportunity of maintaining stable operation of the power system.

The proposed PFR design would re-align power system outcomes in the NEM with standard international practice, and provide the most stable basis for the ongoing rapid transformation of the NEM generation mix that continues to occur. This would maximise the NEM's ability to take on board learnings from other power systems worldwide about how to best manage this transition.

(b) FCAS markets

FCAS markets could continue to operate in their current form, but their role would shift slightly. The objective of FCAS would be to maintain a prudent minimum level of headroom, or frequency control reserve, across the NEM, in the most economic manner. The role that has progressively been assumed for these markets in managing the underlying frequency response characteristics of the entire power system would be removed.

As a result of the design, PFR following contingencies (as for all frequency deviations) would be provided by all generation, not just those enabled to provide Contingency FCAS. This could incentivise additional Generators to offer FCAS, potentially increasing competition for the supply of relevant services. AEMO notes that the requirements of FCAS exceed the proposed PFR requirements in certain areas, such as the specific timing for initiation and termination and the required metering.

The arrangement would not allow for the market and technical allocation of different generating systems to respond to normal and post-disturbance frequency conditions, as is currently permitted via FCAS markets. This is the case even if it could be identified that some generating systems were more marginally suitable for the continuous, small responses required under normal conditions, and some were more marginally suitable for responding to larger disturbances, but not for continuous small deviations in frequency.

It would not allow for any distinction between the marginal ability, willingness, impacts, and ongoing costs of the provision of PFR between different plant, as is currently recognised in FCAS markets. However, the larger the pool of generation that is incrementally responding to frequency on an ongoing basis, the less relevant such marginal operational or efficiency differences become.

(c) Causer pays exposure

AEMO's separate rule change proposal to remove disincentives to the delivery of PFR proposed to clarify the causer pays principles (clause 3.1.56A(k) and amend the associated procedures. Under that proposal, generation operating (on a voluntary basis) within a specified frequency response band inside the NOFB (ultimately a value of ± 0.05 Hz), would be assured of avoiding exposure for that unit to the recovery of Regulation FCAS costs via causer pays. This is consistent with the principle that the generator would effectively be minimising the need for the Regulation FCAS, which is the intent of the causer pays design.

As the proposed deadband for mandatory PFR is narrower than ± 0.05 Hz, all generating systems complying with this requirement would avoid exposure to the recovery of Regulation FCAS costs. This leaves these costs to be recovered from market customers, and potentially a small number of generators exempt from the PFR requirement.

Compared with a 'do-nothing' approach, Regulation FCAS requirements, and the resulting costs, could reasonably be expected to reduce over time with the introduction of PFR. Accordingly, this outcome could be accepted as it is, consistent with the principle of causer pays, or addressed through a review of the design of the Regulation FCAS recovery mechanism. For example, the causer pays process could perhaps be replaced with a simpler cost recovery process aligned with the existing principles for recovery of Contingency FCAS costs.

Outcomes with the widest frequency response deadband

At the other extreme, specifying a frequency response deadband of ±0.500 Hz would mean the mandatory provision of PFR would be a rare event, and is likely to require fewer generating system changes than a narrower band specification. . However, power system frequency performance is likely to further degrade, which could itself have adverse operational impacts on generation, as synchronous generating units continuously and automatically varied their speed to follow the frequency of the power system.

Such a wide deadband would reduce the technical role of the PFRR to a response to events where frequency was already beyond that required to be maintained following a credible contingency event. FCAS markets would therefore remain the sole mechanism for coordinating frequency response under normal operating conditions and following the occurrence of credible contingency events, thereby likely preserving the value of these existing markets. Such a design would be reflective of the underlying principles in existing FCAS markets, where the inherent frequency response characteristics of the power system itself are coordinated only through markets for almost all operating conditions.

While it would have little immediate impact on Generator operations or FCAS markets, a wide deadband PFR requirement would also deliver very little benefit. It would:

- Do nothing to improve the ongoing control of NEM frequency under normal conditions.
- Do the least to improve power system resilience, and would represent the least acceptable engineering outcome.
- Allow frequency to change by half the level required for UFLS or OFGS to be triggered before any response is initiated from generation outside the FCAS markets, significantly reducing the time and margin available for correction of the frequency deviation before these emergency responses come into play.
- Provide no additional guidance or insight for modelling and analysis on expected responses from generation, and the power system overall, for events where frequency remained within ±0.500 Hz for 'Generation Events' or 'Load Events' (as specified in the FOS), which covers the vast majority of disturbances.

Perverse consequences of a wide frequency response deadband

The specification of a wide band PFR requirement not only does nothing to assist frequency control under normal operating conditions; it could also accelerate its decline if more Generators seek to limit their existing provision of PFR within the wide band.

At present, AEMO understands that a significant number of large generating systems provide PFR at or near the limits of the NOFB, currently set at ±0.150 Hz, irrespective of FCAS market outcomes. Some others, but by no means all, modify their delivery of PFR based on FCAS market enablement. There are many reasons for these approaches; some related to the complexity and sophistication of the generator control systems, and some related to the operational impacts on plant of operating in frequency response mode in current power system conditions.

Setting a mandatory PFR deadband wider than the NOFB would signal to Generators currently providing PFR outside of FCAS markets that they could, and perhaps should, further widen their existing PFR deadband. This would likely have the perverse outcome of reducing the PFR provided in response to all but the most extreme disturbances, making all disturbances more difficult to recover from. . This would entirely undermine the purpose of this rule change proposal, which is to improve, not degrade, the frequency performance and resilience of the power system to disturbances.

Because of these outcomes, AEMO would strongly oppose any proposal for a mandatory PFR obligation set at a very wide level.

Outcomes with a frequency response obligation only outside NOFB

If the proposed PFR deadband were set at the edges of the NOFB and assuming the FOS can be met under normal operating conditions, generation would only be obliged to provide PFR less than 1% of the time.

As a result, frequency control under normal operating conditions and following disturbances would continue to be treated as separate matters, allowing for the potential allocation of different generating systems or control responses to manage these two different situations, as occurs today in existing FCAS markets.

Setting PFR deadbands in this manner would not be equivalent to the requirements imposed on Contingency FCAS providers; FCAS markets have more onerous obligations to ensure particular amounts of response are delivered under specific time limits and delivery characteristics, as well as having to provide various measurements to AEMO.

A deadband commensurate with the NOFB would have no impact on the effective control of frequency under normal operating conditions. The NEM would remain an international outlier with respect to power system frequency control, at a critical time when the NEM is leading the rate of integration of inverter-connected generation.

It would, however, go some way to improving the resilience and predictability of power system performance. This setting would ensure that all generation that is potentially capable of providing PFR is always required to provide PFR (to the extent it is able) when a significant power system disturbance has occurred, maximising the overall control response at this level and reducing the physical contingency response burden on any individual unit.

AEMO considered the possibility of limiting this rule change to addressing the resilience issues, with a PFR requirement set at the NOFB level to improve the response to contingency events. This would have left AEMO reliant on adjusting parameters in the small number of mechanisms available, in an attempt to prevent frequency control in normal conditions from deteriorating further. Ultimately, AEMO rejected this approach in favour of a narrower response requirement that will deliver better frequency control under normal operating conditions. The importance of tight frequency control was highlighted by Dr Undrill's advice, with the discrepancy between NEM practice and standard utility practice worldwide also being a key factor in AEMO's decision.

12.2.2 Droop

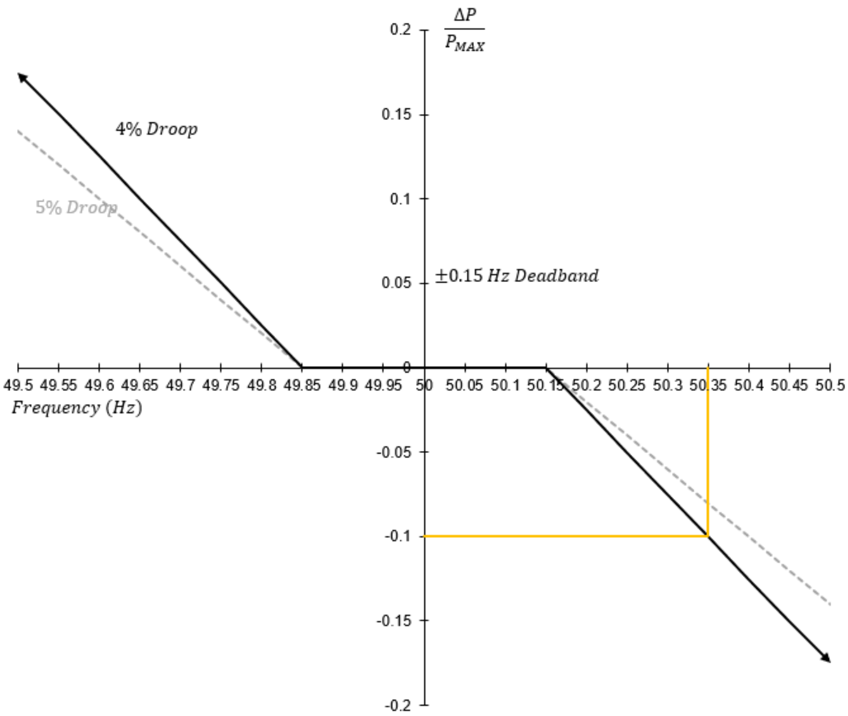
A maximum steady state droop setting of 5% is specified, consistent many power systems worldwide. Such settings have been determined empirically, over more than a century of operating experience, to be appropriate for a wide range of synchronous generating technologies. Equivalent settings may be readily applied to asynchronous generation, however long term experience with settings for asynchronous generating technologies providing frequency response is less extensive.

Lower droop settings may be applied, and no minimum will be specified under the current proposal. Different droop settings may be applied for rising or falling frequency allowing, for example, generation to provide more PFR for falling frequency than for rising frequency.

The response of a generating unit with a 4% droop characteristic and a deadband of ±0.150 Hz is displayed in Figure 11. With these settings, a sustained change of 0.2 Hz beyond the deadband will give an active power change of 10%.

A 5% droop characteristic is shown (dashed) for comparison.

Figure 11 Droop Characteristic



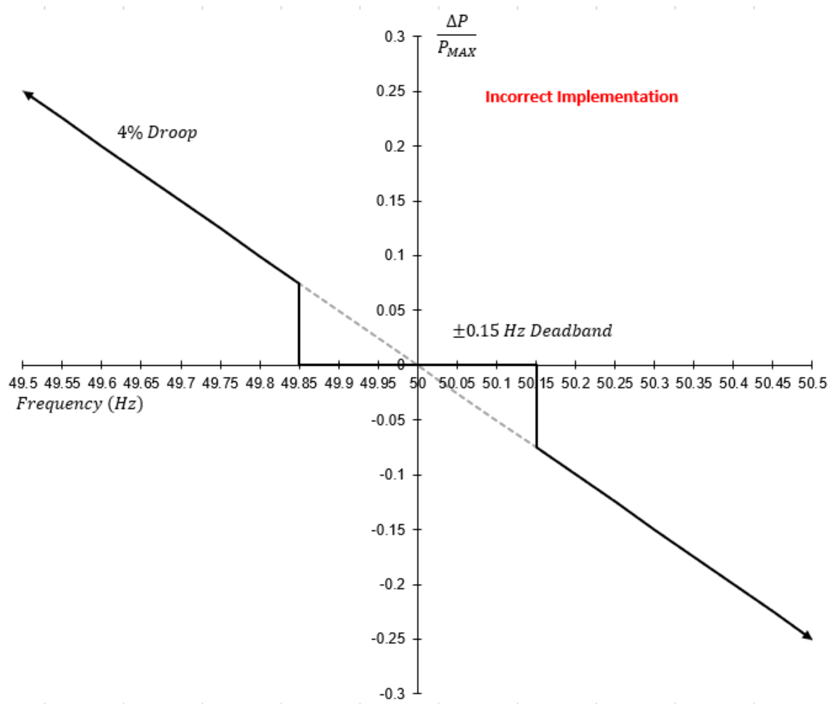
12.2.3 Response at the edge of the frequency deadband

Delivery of PFR should begin in a continuous manner at the edge of the PFR deadband. There should not be a step change in output, or discontinuity of response.

Discontinuity of response increases the risk of oscillatory or poorly damped power system outcomes, particularly where the change in output is large, or there is a significant delay between a change in power system frequency and a change in output. The droop characteristic must not have any stepped discontinuities outside those intrinsic in the response, such as backlash in mechanical linkages.

An example of an incorrect implementation of PFR containing discontinuities at the edge of the deadband is shown in Figure 12.

Figure 12 Stepped Discontinuity in Droop Characteristic



12.2.4 Speed of response

AEMO has proposed that the PFFR will specify a speed of response requirement of 10 seconds for a 5% change in MW output, in response to a sufficient step change in frequency.

Generating systems have a wide range of response capabilities. While faster response times may be more supportive of the power system, so long as they are stably controlled, PFR remains supportive to the power system when delivered over a range of timeframes.

Care needs to be taken when assessing the potential speed of response and control tuning, to ensure settings applied are compatible with the underlying physical characteristics of the plant, and to avoid any potential interactions with other plant control systems.

This relatively low response time requirement has been proposed to avoid creating potential compliance issues for some Generators with slow response capability, while still providing a minimum expectation.

A Generator whose plant is unable to meet this response requirement due to primary energy availability would not be in breach of these requirements.

AEMO views this response time requirement as consistent with the minimum access standard in clause S5.2.5.8 of the NER (Protection of generating systems from power system disturbances) and the minimum access standard in clause S5.2.5.7 of the NER (Partial load rejection).

Based on a review Generators' registered performance standards, AEMO notes that only a few have these performance standards set at the minimum access standard, with most capable of performance closer to the automatic access standard.

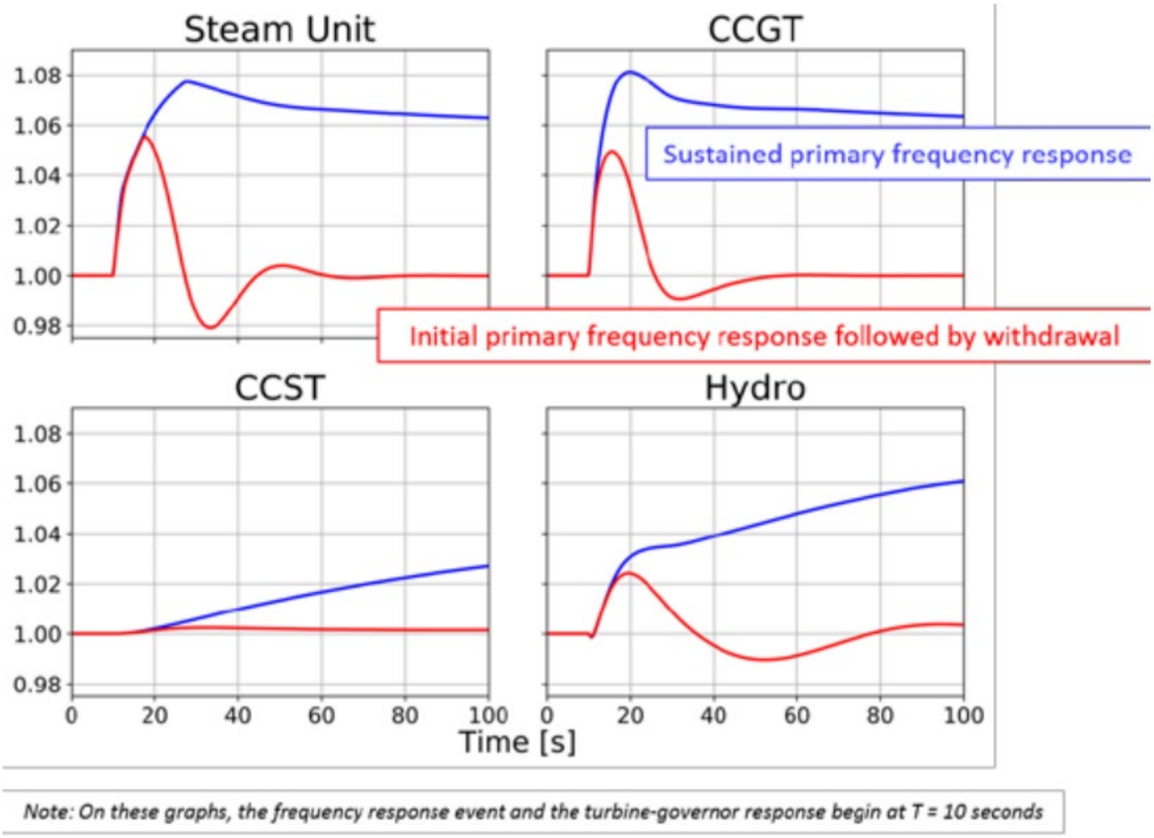
12.2.5 Sustaining response

Where plant is capable of stably and safely doing so, it should sustain its provision of PFR while frequency remains outside the PFR deadband. Withdrawal of PFR by a Generator while frequency remains outside the

PFR deadband will either require others to provide more PFR to replace the gap, or frequency will move further away from 50 Hz.

Comparisons of sustained PFR, and withdrawal of PFR from nominal simulations of various generation technologies are shown in Figure 13[63].

Figure 13 Comparison of sustained PFR vs withdrawal of PFR.



Nevertheless, the PFRR does not specify a sustain time for the delivery of PFR. In this respect, the PFRR differs from the MASS, which requires that generating systems delivering PFR in the form of Contingency FCAS must be capable of delivering PFR consistent with its plant's FCAS market enablement, which will include an ability to sustain a response over a period appropriate for that Contingency FCAS.

Specifically, PFR should not be deliberately withdrawn to enable a Generator to return plant to its market dispatch target while frequency remains outside the PFR deadband. In particular, secondary unit MW control systems or plant load controllers local to the power station or plant should not be used to withdraw or defeat initial delivery of PFR to ensure dispatch compliance, while frequency remains outside the PFR deadband.

Instead, these secondary plant load control systems should be arranged to support, and sustain where possible, the response of the plant to a sustained change in frequency. Including a frequency bias value on the load reference for the unit, appropriately coordinated with the droop setting on the unit speed governor, is a well established way to achieve this outcome.

Nevertheless, AEMO acknowledges that there are many reasons why plant might not be capable of sustaining its response, such as primary energy or environmental limits, or physical limits related to plant

[63] Source: Eto, Joseph H, John Undrill, Peter Mackin, and Jeffrey Ellis. Frequency Control Requirements for Reliable Interconnection Frequency Response. 2018. LBNL-2001103.

capability or safety, such as operating temperature limits, rough running zones, or pressure limits. A Generator would not be in breach of these requirements if it was unable to sustain PFR for such reasons.

12.2.6 Unnecessarily restricting or limiting PFR

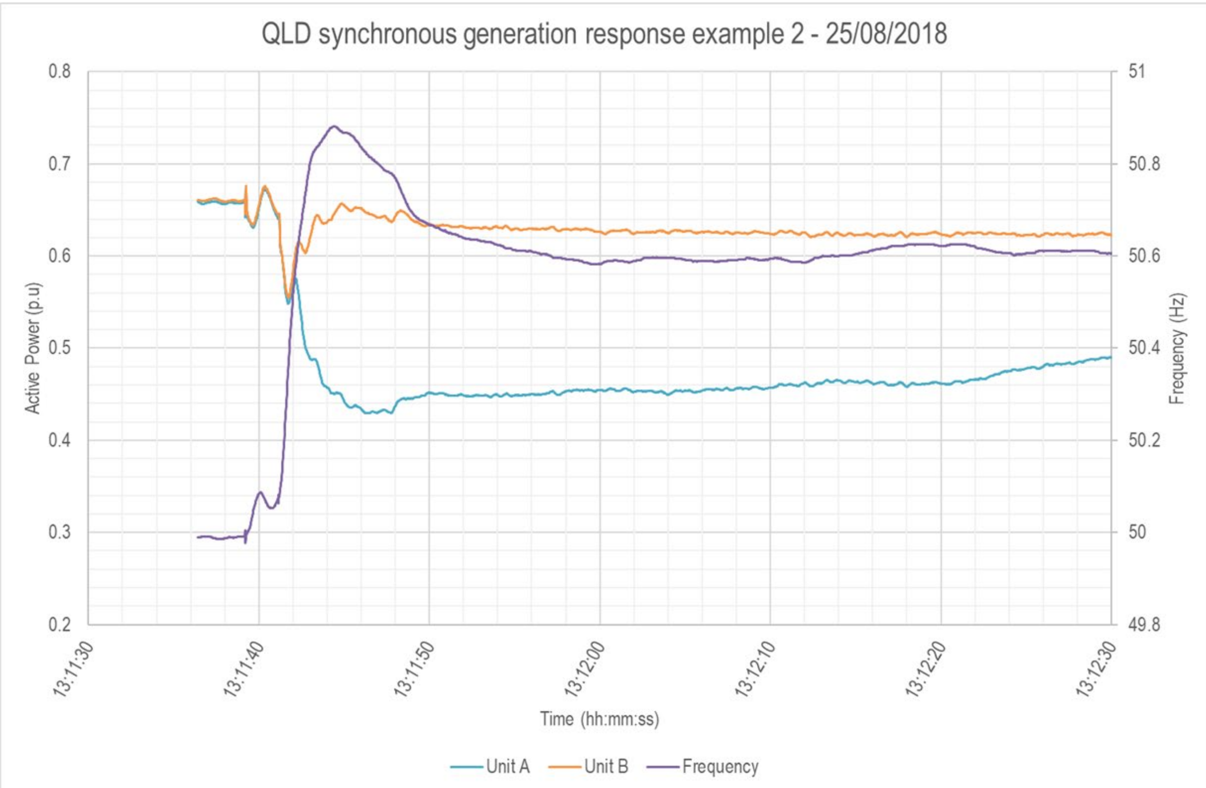
AEMO understands that some generating systems operate with control systems that limit or restrict the delivery of PFR to a level that is close to, or consistent with, their Contingency FCAS enablement, or to no more than their registered Contingency FCAS capability. Under some operating conditions this can limit the delivery of PFR below the level the plant may be capable of safely and stably delivering.

While the MASS requires delivery of a certain level of PFR in response to certain frequency changes when a generating unit is enabled for Contingency FCAS, it does not prohibit or penalise the delivery of PFR beyond this level, and it is not the intention of the MASS that a Generator must not deliver any PFR beyond the level consistent with their Contingency FCAS enablement.

Under the PFRR, a Generator should not use its control systems to artificially limit or restrict the delivery of PFR to a level below what its plant could otherwise safely or stably deliver, if the limit was not introduced.

Figure 14 shows a measured example of two units at a power station in QLD, where one generating unit is limiting the PFR delivered in response to a disturbance, and the other is not. The restriction of response shown from Unit B would not be consistent with the requirements of the PFRR.

Figure 14 Example of restricted or limited PFR



12.2.7 No requirement for headroom

There will be no requirement for any plant to reserve headroom to rise or lower output. If plant is unable to raise output in response to falling frequency, or lower output in response to rising frequency due to a lack of available headroom, it will not be non-compliant.

This contrasts with the MASS, which requires that a Generator must be capable of delivering PFR consistent with its FCAS market enablement.

Management of headroom for frequency response following contingency events would continue to be managed via the Contingency FCAS markets, which would operate unaffected by this proposal. There would be no reduction in the volumes of Contingency FCAS procured as a result of this rule change.

12.3 No accrued rights

AEMO is cognizant of an argument that might be made that the imposition of new obligations on Generators could infringe their 'accrued rights' under connection agreements. Notably, in the context of mandating headroom, the AEMC has stated that 'imposing new requirements on existing generators might be challenging legally as it has the potential to impact on the accrued rights of generators under existing connection agreements'[64] AEMO understands this refers to clause 33(1) of schedule 2 to the National Electricity Law.

The content of connection agreements between Generators and Network Service Providers is prescribed by the NER, notably Schedule 5.6, which includes, among other things, the performance standards that apply to the connected generating system.

Performance standards are based on the access standards in Schedule 5.2 of the NER. Frequency response requirements in the access standards (clause S5.2.5.11) have changed to some extent over time, but have always required generating systems to be capable of frequency response at least from the outer limits of the NOFB. Currently, clause S5.2.5.11(c)(2) requires all generating systems to have automatic PFR capability. The proposed requirements of this rule have been drafted to remain consistent with these required capabilities. It is the changes to clause 4.4.2 of the NER, rather than the performance standards themselves, that have modified and ultimately removed the obligation to operate in frequency response mode unless enabled for FCAS. The effect of the proposed rule would be to reinstate that obligation.

AEMO contends that the absence of an obligation cannot be an accrued right, and the imposition of a forward-looking obligation cannot affect a right or liability as it applied before the rule was made. Similarly, the loss of an ongoing entitlement to be paid for providing a response capability will not impact the accrued right to be paid for that capability if it was provided as FCAS prior to the amendment of the rule.

In terms of the cost of modifications required to comply with the proposed obligation, AEMO considers that the proposal to compensate relevant Generators for any material capital costs associated with equipment changes, where required, will address implementation concerns. AEMO expects the ongoing costs of providing PFR would be minimal because a large proportion of generation in the NEM will be providing that response where required.

12.4 Comparison of proposed PFR requirements to international practice

As outlined in Section 6, a range of different arrangements are used worldwide to ensure adequate delivery of PFR, and availability of adequate MW reserves to respond to defined events. A common, but not universal, approach is to require the ongoing delivery of PFR from all plant, but to manage frequency response reserves via a range of market arrangements. This is consistent with the approach AEMO proposes in this rule change proposal.

Comparisons with other power systems suggest that the proposed PFR deadband specified is consistent with international standards for power systems that are most comparable with the NEM. AEMO considers

64 Draft Report: Frequency Control Frameworks Review, 20 March 2018, at page 156. Available at: https://www.aemc.gov.au/sites/default/files/2018-03/Draft%20report.pdf.

synchronously islanded power systems such as Ireland (smaller than the NEM, +/- 0.015 Hz) or Texas (larger than the NEM, +/- 0.017 Hz) are the most directly relevant comparison points, rather than individual national power systems that ultimately form parts of (much) larger synchronous interconnections.

The key droop settings proposed in this rule change proposal lie within the ranges used in major power systems worldwide as shown in Table 5.

13. EXPECTED BENEFITS AND COSTS OF THE PROPOSED RULE

13.1 Costs of Doing Nothing

The highest cost of doing nothing is the cost of a major supply disruption that could have been avoided if the power system was more stable, and was therefore more resilient to disturbances.

In its report, DIgSILENT identified several other consequences associated with doing nothing, which means permitting frequency performance to continue to deteriorate[65]. Most of these were either possible or almost certain, and they include:

- Increased wear and tear on plant due to increasing movement caused by greater frequency deviations.
- Reduction in the efficiency of generation due to changes in output as a result of deteriorating frequency regulation and governor response.
- Reduction in power system security for contingencies that result in significant changes in power transfer across interconnectors.
- Potential need for additional Contingency FCAS to maintain power system security considering the increase in power system frequency volatility.
- Increase in Regulation FCAS costs without a commensurate benefit.
- Further withdrawal of PFR due to the added burden on the remaining Generators providing PFR.

13.2 Costs of proposed rule

The expected costs of the proposed rule on Generators are expected to vary, but can be summarised as follows:

13.2.1 Upfront costs of changes to plant controls

Some Generators will incur material up-front costs to change their plant controls to provide PFR in compliance with the proposed rule and PFRR. Where they are material, the proposed rule includes provision for Generators to recover these up-front costs. These costs will be unique for every generating system, however, based on advice from several major Generators, in many cases, they are relatively minor.

13.2.2 Ongoing costs of provision of PFR

There is no provision for the recovery of ongoing costs associated with provision of PFR in compliance with these requirements. As Generators would not be obliged to reserve headroom, alter their energy dispatch target, or provide any guaranteed level of response, and the widest possible pool of generation would be

[65] Noted by DIgSILENT in its report on page 49.

required to incrementally contribute, AEMO considers that ongoing costs associated with the provision of PFR required by the proposed rule are minimised with this design.

13.2.3 Increase in plant wear and tear

AEMO notes Generators' concerns about the increase in wear and tear on plant attempting to correct frequency deviations. As the proposed rule requires all capable generating units to provide PFR when capable of doing so, the impact on each of them individually would be minimised to the greatest degree possible. It is noted that the impact of the provision of PFR at any level can be plant specific, and the wear and tear impacts would, therefore, also be expected to be plant specific.

International evidence of the impact of providing broadly distributed PFR on wear and tear is extremely limited. The only evidence readily available on this matter relates to extreme cases where PFR obligations under normal operating conditions have been allocated only to a small, identifiable sub-set of generation, with a resulting detrimental impact on these particular units. With broad-based PFR participation, wear and tear on any individual plants could reasonably be expected to decrease compared with the position in the NEM today.

13.2.4 Impact on the FCAS markets

The cost of Contingency FCAS has been increasing while the power system's resilience has been decreasing. While the cost increases have been significant, it is noted that the Contingency FCAS markets still represent only around 1.3% of NEM turnover.

Existing FCAS markets provide and guarantee a minimum MW operating reserve to allow for frequency response, and can continue to do so following implementation of this rule change. However, provision of frequency response is proposed to be provided from a broader set of plant that just those enable to provide this minimum MW operating reserve via the Contingency FCAS markets.

If accepted, the proposed rule would result in the provision of a much larger potential volume of PFR outside of the NOFB. At present, PFR outside this band is co-ordinated through the Contingency FCAS markets only.

The proposed rule could, arguably, increase the number of Generators who offer their services into the Contingency FCAS markets, due to the reduced opportunity cost of providing Contingency FCAS. This increased supply may then put downwards pressure on the price of Contingency FCAS, reducing potential Generator revenues from this market.

13.3 Potential Benefits of Proposed Rule

The potential benefits of the proposed rule are summarised in Section 13.3.

13.3.1 Increased stability of power system frequency

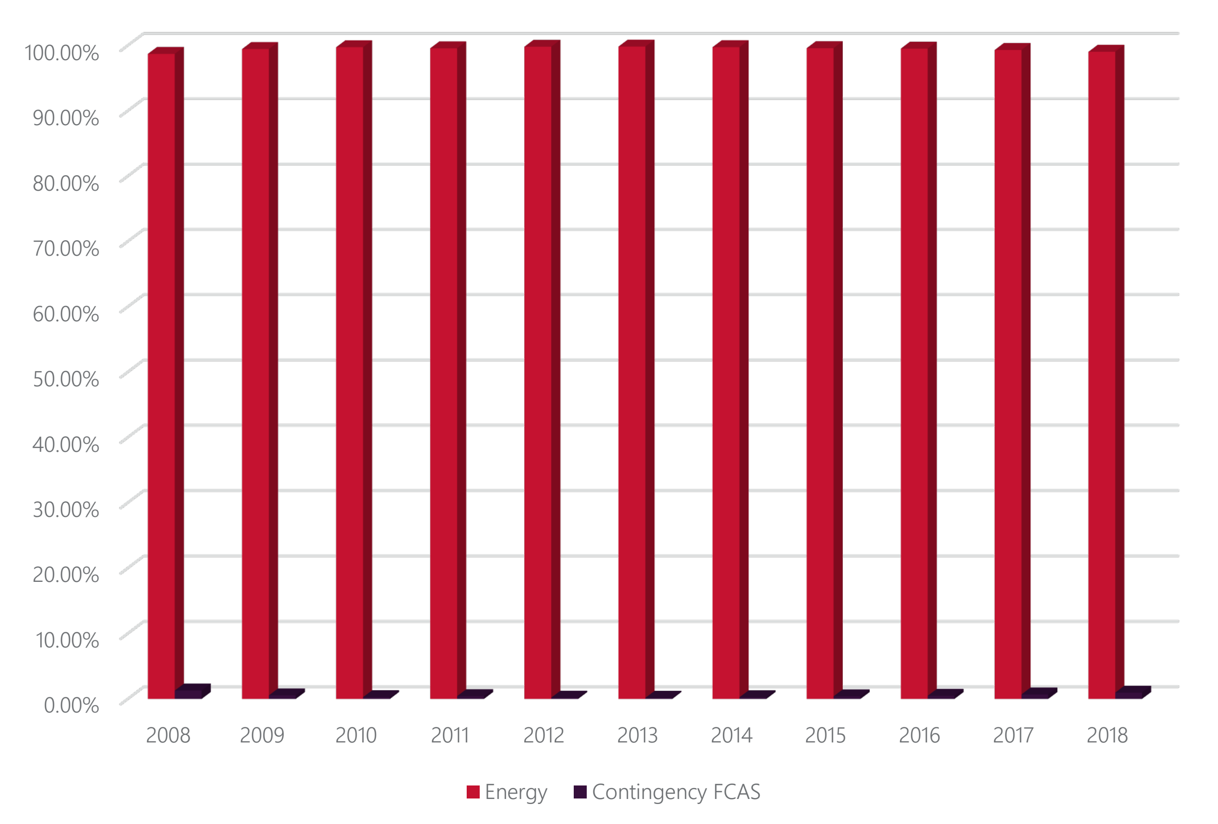
This rule change would undoubtedly lead to a more stable frequency environment in the NEM, particularly in comparison to the current outcome of near-uncontrolled frequency the majority of the time. Effective frequency control is desirable from a power system performance perspective, particularly when considering the NEM in its entirety as the single largest and most complex machine in the country. It would reduce the magnitude of ongoing, poorly controlled frequency oscillations and provide a more acceptable basis for the ongoing and rapid transformation of the NEM generation fleet.

13.3.2 No material increase in ongoing costs to consumers

This proposed rule is not expected to materially increase ongoing costs to consumers, particularly due to the broad based obligation on the largest possible pool of generators to respond.

The costs of Contingency FCAS to date have been relatively low, never more than 1.3% of the total trades in the NEM, as shown in Figure 15:

Figure 15 Comparison of the relative cost of Contingency FCAS vs energy traded in the NEM



As noted in Section 13.2.4, there may be some unintended downwards pressure on costs for Contingency FCAS due to an increase in potential suppliers of these services.

13.3.3 Increase in power system resilience

Contingencies on the power system are inevitable, and greater frequency control will increase the power system's resilience to such events. In turn, this is likely to assist AEMO in managing them and reducing the size of their impact.

Resilience is particularly important in the current environment of rapidly changing technical characteristics of the NEM power system as the generation mix changes, bringing with it new and, sometimes, unpredictable and undesirable responses to disturbances.

The FCAS markets are increasingly reliant on all plant operating exactly as required, with no unexpected responses following a disturbance. There are no deliberate safety margins built into this design, and the historical safety margins that have provided some buffers in the power system are being eroded as delivery of PFR outside the FCAS markets is reduced.

13.3.4 Greater predictability of power system response to disturbances

The ability to predict the response of the power system following disturbances with confidence is vital when modelling power system performance, particularly when designing emergency control schemes, such as UFLS or OFGS.

The FCAS markets do little to ensure predictable response from any individual part or region of the power system, but only generally ensures overall response where the power system remains intact. The predictability of response from all components of the power system is important, especially when responding to larger disturbances.

13.3.5 Minimise risk of load or generation shedding

Greater provision of PFR from generation is likely to reduce the need for load or generation shedding as a correction to more severe supply-demand mismatches and placing it where it should be: a last resort.

It will assist in bridging the gap in expected power system performance between events that are managed by the FCAS markets and emergency responses, such as UFLS or OFGS.

13.4 Balancing the costs and benefits of the proposed rule

AEMO submits that the parts of the NEO that are relevant to this rule change proposal are the efficient investment in, and efficient operation and use of, electricity services with respect to the price and the reliability of supply because:

- Frequency is a vital aspect of power system operation that directly affects the reliability of the power system when it is not in balance and can affect the supply of electricity to consumers. AEMO's reduced ability to control power system frequency through PFR means that AEMO must rely more after disturbances on emergency schemes for controlling frequency, such UFLS and OFGS.
- The proposed rule should be made because the complementary measures AEMO described in Section 7 are only expected to have marginal impact on the frequency performance of the power system but are the only measures that AEMO can take in the absence of the proposed rule.
- The direct costs associated with the provision of PFR in accordance with the proposed rule will be passed on to Market Participants who, ultimately, would be expected to pass those on to consumers. AEMO expects these direct costs to be relatively small, and to be offset by the benefits of making the rule, including increasing the resilience of the power system to major disturbances, and reduced risk of load shedding or other major supply interruptions.

AEMO submits that the proposed rule meets the rule-making test because:

- The AEMC has stated in the past that 'a reliable power system is a crucial part of the energy market and the long-term interest of consumers'[66]. AEMO is unable to achieve any real improvement in the control of power system frequency using the current tools available to it under the NER. AEMO notes that the AEMC has previously considered the extent of potential changes underway in the NEM and the ability of current frameworks to adapt and address the consequences of those changes as a relevant consideration[67]. The AEMC has made changes to the NER where it was likely that continuing with existing arrangements would not be in the long-term interests of consumers. Having UFLS as the only tool to control under-frequency following a major disturbance has far more economic impact than the solution that the proposed rule provides. PFR will minimise the risk that UFLS (or OFGS) will be used.
- The proposed PFR requirement will improve the efficient operation of the NEM by increasing predictability in how connected plant and the power system as a whole will behave following a major

[66] See page 31, Rule Determination, National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, 2 May 2019. Available at: https://www.aemc.gov.au/sites/default/files/2019-05/Final%20Determination.pdf.

[67] See page 16, Rule Determination, National Electricity Amendment (Emergency frequency control schemes) Rule 2017, 30 March 2017. Available at: https://www.aemc.gov.au/sites/default/files/content/5dad7625-02cd-4b3b-b52d-b70d1b2609ea/Emergency-frequency-control-schemes-Final-rule-determination-%28FINAL-PU.pdf

disturbance. A better understanding of how the power system will perform under a range of conditions would facilitate more efficient operation of the power system and procurement of appropriate levels of FCAS as well as how the power system will react to contingencies.

- Mandatory broad-based PFR will improve the accuracy of planning for contingencies, and a more efficient planning process will benefit consumers by facilitating better decisions by AEMO to achieve better power system security and reliability outcomes.
- The costs to be incurred by those who would need to comply with the proposed rule would not exceed the benefits to be gained both now and in the longer term by consumers, noting that any material up-front costs of compliance with the proposed rule would be recoverable by Generators. The proposed rule is a proportional solution to the issue, the extent of potential improvements in the security and reliability of the power system and the efficiency of planning processes and price impacts.
- If all capable generation were required to provide PFR, the financial burden on each Generator would be minimal and could be absorbed across the market more easily. AEMO is aware that many Generators would prefer to be paid for providing PFR, however, it is also relevant to consider whether Generators who have made conscious decisions to reduce or disable their capability to do so should subsequently be paid to stop making power system frequency control worse.

APPENDIX A. GLOSSARY

This proposal uses many terms that are defined in the NER and are intended to have the same meanings. Common abbreviations for terms and measures are set out below:

Abbreviation/Term	Term/Meaning
AEMC Final Report	The AEMC's Final Report: Frequency Control Frameworks Review, dated 26 July 2018.
AEMO Incident Report	AEMO Final Report: Queensland and South Australia system separation on 25 August 2018. An operating incident report for the National Electricity Market, 10 January 2019.
AER	Australian Energy Regulator
AGC	*Automatic generation control*
causer pays	The principle underlying the NER framework for recovering the costs payable to Regulation FCAS providers. It requires determination of the extent to which suitably metered market generating systems or loads have contributed to the need for regulation frequency control.
Contingency FCAS	*Fast raise service*, *fast lower service*, *slow raise service*, *slow lower service*, *delayed raise service*, and *delayed lower service*.
Contingency Lower FCAS	*Fast lower service*, *slow lower service* and *delayed lower service*
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
FCAS	Frequency control ancillary service, a general term applied to describe *market ancillary services*.
FOS	*Frequency operating standard*
Generator	*Generator*
kV	kiloVolt (1,000 Volts)
MASS	*Market ancillary service specification*
MW	MegaWatt (1,000,000 Watts)
NEM	National Electricity Market
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NOFB	*Normal operational frequency band*
NSW	New South Wales
OFGS	Over-*frequency* generator shedding
PFR	Primary frequency response
PV	Photovoltaic
QLD	Queensland
QNI	QLD–NSW interconnector
Regulation FCAS	*Regulating raise service* and *regulating lower service*.
SA	South Australia
SCADA	Supervisory control and data acquisition
TAS	Tasmania
TNSP	*Transmission network service provider*
UFLS	Under-*frequency load shedding*
VIC	Victoria

APPENDIX B. DRAFT RULE

This draft is based on version 121 of the National Electricity Rules.

PROPOSED CHANGES TO CHAPTER 4

4.4.1 Power system frequency control responsibilities

AEMO must use ~~its~~ reasonable endeavours to:

(a) control ~~the~~ *power system frequency*; and

(b) ensure that the *frequency operating standards* ~~set out in the *power system security standards*~~ are achieved.

4.4.2 Operational frequency control requirements

To assist in the effective control of *power system frequency* by *AEMO*, the following provisions apply:

(a) *AEMO* may give *dispatch instructions* in respect of *scheduled generating units*, *semi-scheduled generating units*, *scheduled loads*, *scheduled network services* and *market ancillary services* pursuant to rule 4.9;

(b) each ~~Each~~ *Generator* must ensure ~~that~~ all ~~of~~ its *generating units* meet the technical requirements for *frequency*~~frequency~~ control in clause S5.2.5.11;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(c1) each *Scheduled Generator* and *Semi-Scheduled Generator* must operate its *generating system* in accordance with the *Primary Frequency Response Requirements* as applicable to that *generating system*;

(c) *AEMO* must use ~~its~~ reasonable endeavours to arrange to be available and ~~specifically~~ allocated to *regulating duty* such *generating plant* as *AEMO* considers appropriate ~~which can be automatically controlled or directed~~ for automatic control or direction by *AEMO* to ensure that all normal *load* variations do not result in *frequency* deviations outside the limitations specified in clause 4.2.2(a); and

(d) *AEMO* must use ~~its~~ reasonable endeavours to ensure that adequate *facilities* are available and ~~are~~ under the direction of *AEMO* to allow the managed recovery of the *satisfactory operating state* of the *power system*.

4.4.2A Primary Frequency Response Requirements

(a) *AEMO* must develop and *publish*, and may amend, the *Primary Frequency Response Requirements* in accordance with the *Rules consultation procedures*. The *primary frequency response requirements* must include:

(i) a requirement that *Scheduled Generators* and *Semi-Scheduled Generators* set their *generating systems* to operate in *frequency response mode* within one or more performance parameters;

(ii) the performance parameters referred to in subparagraph (i) include deadbands, droop and response time, which may be specific to different types of *plant*;

(iii) the conditions or criteria on which a *Scheduled Generator* or *Semi-Scheduled Generator* may request, and *AEMO* may approve, a variation to, or exemption from, any performance parameters applicable to its *scheduled generating system* or *semi-scheduled generating system*;

(iv) details of the information to be provided by *Scheduled Generators* and *Semi-Scheduled Generators* to verify compliance with the *Primary Frequency Response Requirements* and any compliance audits or tests to be conducted; and

(v) *AEMO* must publish on its website a list of *Scheduled Generators* and *Semi-Scheduled Generators* who are exempt from the *Primary Frequency Response Requirements*.

(b) *AEMO* may make minor or administrative amendments to the *Primary Frequency Response Requirements* without complying with the *Rules consultation procedures*.

Clauses 4.9.4 and 4.9.8 will also need to be amended as follows if AEMO's separate rule change proposal (Removal of disincentives to the provision of primary frequency response under normal operating conditions) is not made prior to this rule.

4.9.4 Dispatch related limitations on Scheduled Generators and Semi-Scheduled Generators

A *Scheduled Generator* or *Semi-Scheduled Generator* (as the case may be) must not, unless in the *Generator's* reasonable opinion, public safety would otherwise be threatened or there would be a material risk of damaging equipment or the environment:

(a) send out any *energy* from a~~the~~ *generating unit*, except:

(1) in accordance with a *dispatch instruction*;

(2) in response to remote control signals given by *AEMO* or its agent;

(3) in connection with a test conducted in accordance with the requirements of this Chapter or Chapter 5;

(3A) as a consequence of its operation in *frequency response mode* to adjust *power system frequency* in response to *power system conditions*; or

(4) in the case of a *scheduled generating unit*~~:~~,

~~(i)~~ in accordance with the *self-commitment* procedures specified in clause 4.9.6 up to the *self-dispatch level*; ~~or~~

~~(ii) as a consequence of operation of the *generating unit's* automatic *frequency response mode* to *power system* conditions;~~

…

4.9.8 General responsibilities of Registered Participants

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

(a1) A *Scheduled Generator* or *Semi-Scheduled Generator* is not taken to have failed to comply with a *dispatch instruction* as a consequence of the operation of a *generating unit* in *frequency response mode* to adjust *power system frequency* in response to *power system conditions*.

PROPOSED CHANGES TO CHAPTER 5

Clause S5.2.5.11(i)(4) will also need to be deleted if AEMO's separate rule change proposal (Removal of disincentives to the provision of primary frequency response under normal operating conditions) is not made prior to this rule.

S5.2.5.11 Frequency control

…

(i) For the purposes of subparagraph (b)(2), and with respect to a *negotiated access standard* proposed for the technical requirements relevant to this clause S5.2.5.11:

…

(3) nothing in subparagraph (b)(2) is taken to require a *generating system* to operate below its minimum operating level in response to a rise in the *frequency* of the *power system* as measured at the *connection point*, or above its maximum operating level in response to a fall in the *frequency* of the *power system* as measured at the *connection point*; <u>and</u>

(4) ~~a *generating system* is required to operate in *frequency response* mode only when it is enabled for the provision of a relevant *market ancillary service*; and~~ <u>[Deleted]</u>

…

PROPOSED CHANGES TO CHAPTER 10

New Definitions

<u>***primary frequency response***</u>

<u>An automatic change in a *generating system's active power* output to arrest locally-measured *frequency* changes outside one or more parameters specified in the *Primary Frequency Response Requirements* to correct the *frequency* deviation.</u>

<u>***Primary Frequency Response Requirements***</u>

<u>The requirements *published* by *AEMO* under clause 4.4.2A(a).</u>

PROPOSED CHANGES TO CHAPTER 11

Part ZZZX Primary frequency response following contingencies

11.1XX Rules consequential on the making of the National Electricity Amendment (Mandatory primary frequency response following contingencies) Rule 2018

11.1XX.1 Definitions

For the purposes of this rule 11.1XX:

Amending Rule means the *National Electricity Amendment (Mandatory primary frequency response following contingencies) Rule* 2019.

commencement date means [date].

interim primary frequency response requirements means the requirements developed and published by *AEMO* in accordance with clause 11.1XX.2

11.1XX.2 Primary frequency response requirements

(a) *AEMO* must develop and *publish* the interim primary frequency response requirements to apply from the commencement date by XXX.

(b) The interim primary frequency response requirements must include the matters to be included in the *Primary Frequency Response Requirements* under clause 4.4.2A and the following:

(i) the date (which may vary according to *plant* type) by which *Scheduled Generators* and *Semi-Scheduled Generators* must effect changes to their *plant* to comply with the interim primary frequency response requirements; and

(ii) the information and evidence to be provided to support a claim for reimbursement under clause 11.1xx.4.

(c) Any action taken by *AEMO, a Scheduled Generator,* or *Semi-Scheduled Generator* prior to the commencement date in anticipation of the commencement of the Amending Rule is deemed to have been taken for the purpose of the Amending Rule and continues to have effect for that purpose.

11.1XX.3 Reimbursement of costs incurred by Scheduled Generators Semi-Scheduled Generators

(a) A *Scheduled Generator* or *Semi-Scheduled Generator* who has changed its *plant* to provide *primary frequency response* in accordance with the interim primary frequency response requirements may submit a claim to *AEMO* for reimbursement of its costs for doing so, subject to the following conditions:

(i) the relevant *generating system* was *connected* to the *power system* on or before the commencement date;

(ii) the costs exceed a materiality threshold of $XXX per *generating system*, and the claim is limited to costs over that amount;

(iii) the amount claimed does not exceed the amount directly and reasonably required to make the necessary changes to the *plant*;

(iv) the claim is accompanied by the information and evidence specified in the interim primary frequency response requirements; and

(v) the claim is submitted on or before the date that is 12 months from the commencement date.

(b) *AEMO* must approve the claim to the extent that *AEMO* is satisfied the conditions in paragraph (a) are met, and otherwise must not approve the claim.

(c) A *Scheduled Generator* or *Semi-Scheduled Generator* whose claim is rejected by *AEMO* may dispute *AEMO's* decision in accordance with rule 8.2.

(d) *AEMO* must pay the amount approved or determined under paragraph (b) or (c) to the relevant *Generator Scheduled Generator or Semi-Scheduled Generator* by the later of 20 *business days* of:

(i) *AEMO's* approval of the claim under paragraph (b); or

(ii) a *DRP's* determination.

11.1XX.5 Recovery of costs by AEMO

(a) The introduction of requirements to provide *primary frequency response* under the Amending Rule is taken to have been determined as a *declared NEM project* on the commencement date.

(b) *AEMO's* costs to be recovered for the *declared NEM project* under paragraph (a) comprise:

(i) amounts reimbursed to *Scheduled Generators* and *Semi-Scheduled Generators* as contemplated by clause 11.1xx.4;

(ii) *AEMO's* costs and disbursements associated with the determination and approval of claims; and

(iii) *AEMO's* costs and disbursements associated with any dispute resolution process to determine claims for reimbursement.

(c) *AEMO* must allocate the costs described in paragraph (b) to *Market Customers, Non-Market Generators, Market Small Generation Aggregators* and *Market Generators* who are exempt from the requirement to provide *primary frequency response* to the extent that their *generating systems* are exempt, based on the relative annual energy they produce or consume (as applicable) and recover it through *Participant fees* as contemplated in the *AEMO* document titled "Final Report - Structure of Participant fees in AEMO'S Electricity Markets 2016" dated 17 March 2016.

(d) *AEMO* must commence recovery of those costs from the commencement of the *financial year* commencing after the first payment under clause 11.1xx.4(d) is made until the date that is one year after the payment of the last claim for reimbursement under clause 11.1xx.4(a).