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Thursday, 31 October 2019

Mr John Pierce AO
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

RE: ERC0263, ERC0274 and ERC0277 – Primary Frequency Response Rule Changes

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (the Commission) Draft Determination to the two rule change requests submitted by the Australian Energy Market Operator for Removal of disincentives to primary frequency response during normal operation and Mandatory primary frequency response and a third rule change submitted by Dr Peter Sokolowski for Primary frequency response requirement.

About ERM Power

ERM Power is an Australian energy company operating electricity sales, generation and energy solutions businesses. The Company has grown to become the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. A growing range of energy solutions products and services are being delivered, including lighting and energy efficiency software and data analytics, to the Company's existing and new customer base. The Company operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland. www.ermpower.com.au

General comments

It is with a sense of deja vu that ERM Power has prepared this submission. The provision of frequency control services in the National Electricity Market (NEM) is an issue that was discussed at length during the original design of the NEM and subject to numerous reviews of both the most efficient way to ensure that this necessary power system service continues to be supplied over the long term as well as the consideration whether the service should be supplied via mandated provision or via a market mechanism. The Commission only concluded its Frequency Control Frameworks Review in July 2018, at which time the Commission rejected AEMO's request to impose mandated primary frequency control requirements on generators and confirmed that in the Commission's view the long term interests of the NEM in accordance with the National Electricity Objective (the NEO) would be best met by the provision of frequency control services via a market mechanism.

At commencement of the NEM, frequency control was provided by a combination of contracted regulation frequency control services and a mandatory requirement that generators operated at all times with a maximum governor dead band setting of +/- 0.050 Hertz (Hz). Generators that had available capacity, (commonly referred to as headroom) were required to respond to a frequency deviation to return the power system to within the Frequency Normal Operating Band (FNOB) as quickly as technically achievable.

[1] Based on ERM Power analysis of latest published financial information.

Notwithstanding, the Australian Competition and Consumer Commission (ACCC) granting the original approval of the National Electricity Market Code, (the rules by which the NEM was to be conducted), this approval required that a review be undertaken to determine the most efficient long term provision of frequency control services to the NEM. This review resulted in the implementation of the eight Market Ancillary Services, most commonly referred to as the Frequency Control Ancillary Service (FCAS) markets which commenced operation in October 2001 and remain in operation today.

There can be no doubt that any review of current power system frequency control outcomes shows that overall, the performance of frequency distribution around 50 hertz (Hz) has changed over time, yet apart from isolated observations, power system frequency has continued to meet the frequency operating standard (FOS), and in particular the requirements of the FNOB as set by the Reliability Panel. It is also worth noting that whilst AEMO have continued to indicate that in their view power system frequency outcomes are insufficient to meet power system security requirements, no request has been submitted by AEMO to review the FOS.

In fact, whilst over the period April 2017 to April 2018, an extensive review of the FOS was undertaken by the Reliability Panel; at no time during this review did AEMO submit that the current profile of frequency outcomes was of sufficient concern from a power system security perspective that the FOS needed to be tightened to achieve a more secure power system frequency profile. It should be noted that the original FNOB at NEM commencement was 49.90 to 50.10 Hz, the FNOB was relaxed following a review of the FOS at which time the market operator advised the Reliability Panel that from an engineering and power system security perspective, the existing tight FNOB was neither justified economically or from a power system security perspective.

ERM Power contends that if power system frequency outcomes are at a level of concern from a power system security perspective as indicated by AEMO in their rule change request, a request for a review of the FOS recommending a tightening of the FNOB and the engineering reasons for such a change, should have been one of the first priorities by AEMO. In 2000, this was the first step undertaken by the then Market Operator to relax the FNOB requirements.

ERM Power does not support all the proposed rule changes, as submitted by AEMO (ERC 0263)[2]. ERM Power also does not support rule change proposals ERC 0274 and ERC 0277[3]. In summary, we believe:

- Primary frequency response is a necessary power system service that is costly to provide. Generators should continue to be compensated for the provision of this service through a market mechanism. A requirement for mandated primary frequency response without compensation removes the necessary economic signal for the provision of these services, which is not in the long term interest of the NEM.
- Muting this economic price signal through the introduction of mandated primary frequency response may deter new suppliers from entering the market increasing costs of service provision over time.
- Power system frequency in general continues to meet the requirements of the frequency operating standard (FOS). The FOS remains the appropriate standard to maintain the economic, operational and security requirements of the NEM. Whilst AEMO indicates that the current frequency outcomes are insufficient, to date no evidence has been provided by AEMO to support a revision of the FOS.
- The tools currently available to AEMO to manage power system frequency are sufficient. The current FCAS markets remain capable of meeting the challenges of effective and efficient provision of frequency control services.

[2] ERC 0263 - Removal of disincentives to primary frequency response during normal operation
[3] ERC 0274 – Mandatory primary frequency response; ERC 0277 – Primary frequency response requirement

Factors impacting current power system frequency outcomes

The current power system frequency outcomes are a function of a number of changes in the NEM, some occurring more rapidly than others and the way in which the NEM's FCAS procurement process has been undertaken by the market operator.

The introduction of asynchronously connected generators, both grid connected and as distributed energy resources (DER) – these generators to date have provided at best very limited contribution to the required power system services to ensure secure operation of the power system including frequency control. This has been compounded by the high level in variability in output within a *dispatch interval* from these generators due to the inherent variability of their input energy source and the operators desire to maximise energy output at all times. As noted by Delta Electricity; "*Scheduled Intermittent Generating sources, by AEMO's own assessments in the published FCAS contribution factors, produce five times causation per MW of output than synchronous machines*[4]."

The retirement of 20 large synchronous generating units between 2012 and 2017 located across all mainland NEM regions resulted in the loss of power system services, including frequency control and inertia previously provided by these units In addition to the direct loss of power system services provided by these units, there has been an equally significant secondary impact where the remaining synchronous generators, particularly at times of tighter supply demand balance, are operating at higher output levels and no longer have excess headroom to provide free frequency services above that procured by AEMO.

The influx of increasing amounts of low input energy cost intermittent generation is increasing the time periods where higher fuel cost synchronous generating units are operating at or close to minimum sustainable output levels, or resulting in unit de-commitment, this in turn reduces the amount of time these synchronous units are capable of supplying both lower FCAS and any mandated lower primary frequency response.

There has been a change in connected demand from that which was primarily "synchronous" in nature, to demand that is connected asynchronously via inverters or other power system electronics. Whilst AEMO have recently undertaken a review, which has identified a reduction in "load relief", the impact of this change on the demand side has also resulted in a reduction in the frequency volatility dampening impact supplied by the cumulative effect of thousands of megawatts of lost synchronously connected load. The impact of this reduction should not be underestimated on system frequency outcomes.

This loss of load relief has manifested with regards to observed frequency outcomes particularly following a credible or non-credible contingency event and has been compounded by the ongoing under procurement of contingency FCAS. AEMO commenced a process of rectifying the under procurement of contingency FCAS on 12th September 2019, however, this process to reduce the level of under procurement is expected to take 5 months to complete.[5] As a participant we are somewhat confused by AEMO's decision to rectify this under procurement of contingency FCAS over such an extended timeframe given the statements in the rule change requests that current power system frequency outcomes are a significant power system security risk.

The loss of the frequency volatility dampening impact whilst less direct compared to the reduction in "load relief", is observable in real time frequency outcomes, whilst AEMO has commenced a process of increasing regulation FCAS to procure sufficient regulation FCAS to offset the loss of this inherent service, further increases in regulation FCAS procurement values may be required.

The removal of the procurement of an additional 120 MW of raise regulation FCAS during periods of power system demand ramping as implemented in June 2006 by the then market operator. This additional raise regulation FCAS at times of fast but variable demand increase reduced the intra dispatch interval frequency variations caused by greater than forecast demand increase.

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[4] Page 4 Delta Electricity submission to AEMC's Consultation Paper – Primary Frequency Response Rule Changes

[5] AEMO - Changes to Contingency FCAS volumes August 2019

It is also worth noting that when the decision was made to alter the FNOB in 2001 and for the market operator to commence a reduction in regulation FCAS procurement volume, protocols were put in place, which were reviewed via a National Electricity Code consultation process[6] and re-confirmed during 2006/2007. This protocol required the market operator to monitor power system frequency performance and increase regulation FCAS procurement if and when required. The level of FCAS procurement was to ensure that the power system did not breach the frequency standards with an increase in procurement volume indicated when either the system frequency breaches a band of 49.8 – 50.2 Hz, in the absence of a contingency event or load event; or the system frequency strays outside a band of 49.85 – 50.15 Hz for more than 0.5% of the time over any 30 day period, or for more than three minutes on any occasion, in the absence of a contingency event or load event.[7] Whilst frequency outcomes have been observed to progressively deteriorate from mid-2014 which breached the monitored levels above, changes to regulation FCAS procurement values only commenced from late 2018.

The emphasis placed on strict compliance with the requirements of clause 4.9 with regards to a *dispatch instruction* by both the Commission[8] and the AER. This resulted in generators not enabled for FCAS targeting strict compliance with their energy market *dispatch instruction* at the expense of the provision of free primary frequency response.

The above issue was compounded by the use of a calculated *frequency influence* value by AEMO in the calculation of regulation FCAS causer pays factors. This calculated *frequency influence* value could at times be out-of-phase with power system frequency requirements. There is also a secondary issue in the causer pays calculation whereby a generator's response to frequency outcomes is based on the time the generators SCADA data energy output is received by AEMO and thus subject to time delay in SCADA data delivery. This second issue could be rectified by the use of the generators local frequency SCADA data. This *frequency influence* error has been removed by a change to use power system frequency as the basis for the causer pays calculation, however, the SCADA time delay issue is yet to be rectified.

Tools available to manage power system frequency outcomes

AEMO has indicated that in their view the Rules provide insufficient tools to effectively manage power system frequency outcomes to maintain a secure power system. The tools available to AEMO include;

<u>Regulation FCAS</u> – currently delivered by an enabled supplier in accordance with the market operator's requirement via AEMO's automatic generator control (AGC) system which delivers a required output target to a generator every four seconds. Regulation FCAS is the primary tool utilised by AEMO for maintaining frequency during the FNOB during system normal conditions.

<u>Contingency FCAS</u> – primary frequency response delivered by a supplier following a contingency event in accordance with the suppliers frequency setting as determined by the market operator and sustained until the power system frequency returns to within a band of 49.90 to 50.10 Hz

<u>Under Frequency load shedding (UFLS)</u> – in the event that the power system frequency falls to a predetermined setting, as set by the market operator, generally following a significant power system event, blocks of load will be disconnected to arrest the fall in system frequency and to stabilise the power system frequency at an acceptable level. All non-sensitive loads are required to participate in the UFLS scheme.

<u>Over Frequency Generation Shedding (OFGS)</u> – in the event that the power system frequency increases to a predetermined setting, as set by the market operator, generally following a significant power system event, contracted generators will be disconnected to arrest the increase in system frequency and to stabilise the power system frequency at an acceptable level. There are little in the way of details published regarding the level of OFGS in the NEM

[6] The National Electricity Code consultation process was replace by the National Electricity Rules – Rules consultation process
[7] NEMMCo FCAS Review Final Report July 2007
[8] Final determination Rule Change Request ERC 0187 - Compliance with dispatch instructions May 2016

<u>Constraining Generator Dispatch or Credible Load Consumption</u> – AEMO has the ability to constrain off generator output or reduce consumption at a load point to manage the size of the largest credible contingency in response to insufficient FCAS capability so that sufficient contingency (primary frequency) response is available for the largest credible contingency event.

<u>Protected event</u> – AEMO can apply for specific non-credible contingency events to be classified as a *protected event*. A *protected event*, whilst having a low probability of occurrence, may, if they do occur, have a significant impact on the secure operation of the power system. Once declared as a *protected event*, AEMO may implement additional actions to mitigate the risk to the power system such as contracted UFLS or OFGS.

<u>Clause 4.8.9 Direction</u> - AEMO may require a Registered Participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state. This includes the provision of primary frequency response via the requirement to operate in *frequency response mode*. A Registered Participant must use its reasonable endeavours to comply with a direction or clause 4.8.9 instruction unless to do so would, in the Registered Participant's reasonable opinion, be a hazard to public safety, or materially risk damaging equipment, or contravene any other law.

Given the extensive suite of tools available to AEMO to manage power system frequency it is unclear to ERM Power how AEMO's claim that it has insufficient tools to maintain power system frequency with regards to secure operation of the power system is entirely valid. Clause 3.11.2 which sets out the requirements for Market Ancillary Services, more commonly referred to as the FCAS markets, sets out the eight FCAS market types, but contains no specific requirements with regards to how the services are to be physically supplied. The actual process by which the designated service is physically supplied is set out in the Market Ancillary Services Specification (MASS) as developed and amended by the market operator in accordance with the *Rules consultation procedure* when amending the MASS.

With specific regards to the provision of the raise and lower regulation services, the Rules do not restrict the physical delivery of the services such that the services may only be provided by use of the market operators AGC system as set out in the current MASS, but rather the service could be delivered by any means specified by the market operator in the MASS, including the provision of primary frequency response initiating from a tight control response dead band setting.

The current delivery of raise and lower regulation services, which AEMO has indicated in their rule change request is in AEMO's view ineffective, is restricted only by AEMO's currently imposed condition that the service must be physically delivered by AEMO's AGC system. As set out above, the physical delivery of all contingency FCAS is supplied by primary frequency response and we see no impediment to regulation FCAS being also supplied by primary frequency response specified within a tight control dead band, with the provision of supplementary response via AEMO's AGC system as and when required. It should also be noted that the New South Wales power system, and potential other state power systems, were operated successfully on a combined primary frequency response and AGC system for dispatch and frequency control prior to the commencement of the NEM.

We note that AEMO's response to the AEMC during the Frequency Control Frameworks Review identified that primary frequency response by itself may reduce the magnitude of any frequency deviation; however, the duration of the deviation remains the same. AEMO also identified that whilst an increase in AGC controlled response reduces the time required rectifying the frequency deviation, compared to primary frequency response by itself, which in turn increases power system resilience, notwithstanding, AGC controlled response by itself does not impact the overall magnitude of the frequency deviation[9]. This demonstrates that improved outcomes regarding frequency control within the FNOB would be achieved when both primary frequency response and secondary AGC response are combined within the regulation FCAS

[9] Pages 14 and 15 Consultation Paper – Primary Frequency Response Rule Changes

On the basis of the above, ERM Power questions AEMO's assertions in their rule change requests that; "*The design of the FCAS markets has proven to be inadequate to address the challenges AEMO now faces"* and "*use of regulation FCAS alone is not capable of controlling frequency within the NOFB under normal operating conditions"*[10].

We contend that the design of the FCAS markets are adequate and remain capable of managing power system frequency under both normal operating and contingency conditions. The only impediments to the FCAS managing power system frequency as originally intended is a result of the ongoing under procurement of FCAS, and the requirement that regulation FCAS be physically delivered solely by AEMO's AGC system.

We urge caution with regards to reassigning contingency FCAS to provide regulation FCAS through a tightening of the settings at which contingency FCAS activates. Contingency FCAS is designed to provide frequency control response to restore the power system frequency to within the FNOB within a short time period following a contingency event. Should this service be appropriated to provide routine frequency control within the FNOB, then it is likely that the capability of the contingency FCAS are reduced at the time they are required to respond to any contingency event. For this reason we do not support any change to allow contingency FCAS to be utilised for regulation FCAS requirements.

Notwithstanding our belief that the FCAS markets remain capable of meeting the challenges of effective and efficient provision of frequency control services, ERM Power also recommends that the Commission consider an additional tool be added to the suite of tools above. This additional tool is in the form of a frequency control safety net provision where all generators, regardless of enablement for provision of FCAS, are required to operate with a frequency control response service at all times to assist frequency restoration following a significant non-credible contingency event to within the FOS interconnected system stabilisation band of 49.50 to 50.50 Hz. This would be a mandated obligation of all generators, with the capability to do so at the time of a significant frequency disturbance event, to provide frequency control response which activates when power system frequency drops below 49.60 Hz or exceeds 50.40 Hz. This would also act as a safety net backup to the failure of the market operator to request the classification of a potential significant non-credible contingency event as a *protected event*.

We reject AEMO's view that a mandated requirement for a frequency control safety net provision would result in generators with existing deadband settings either inside or at the edge of the normal operating band adjusting the deadbands to the safety net setting. Many of these generators would simply leave their governor settings to the current settings due to the difficulty in adjusting them. Others who have the capability to do so, have not adjusted either to widen the settings or disable the governor response when not enabled for the provision of FCAS and would have no additional incentive to do so than that currently provided.

Generators which AEMO believe operate with ether wider governor dead band settings or with governor response disabled when not enabled for FCAS, would now be required to provide the safety net frequency response when power system frequency moved outside the frequency control safety net provision parameters.

25 August 2018 multiple non-credible contingency multiple region islanding event

As discussed in the Paper, no two power system disturbances are ever the same, and whilst AEMO has sought to compare the Queensland region islanding event on 28 February 2008 to the Queensland and South Australia islanding event on 25 August 2018, system conditions and the market operators response at the time of each event varied significantly. We have reviewed the final system incident reports for both events and compiled a summary of what we believe are significant differences in system conditions and the market operators responses during both multiple non-credible contingency events. This summary is set out as an appendix to our submission.

[10] Pages 21 and 22 AEMO Rule Change Request - Removal of disincentives to primary frequency response during normal operation

The double circuit loss of the transmission line between Dumaresq and Bulli Creek remains listed to be reclassified as a double circuit trip for lightning activity and QNI is restricted to 850 MW of southward flow following reclassification. We are not aware of any plan to request classification of the loss of the double circuit transmission lines between Armidale – Dumaresq – Bulli Creek (QNI) as a *protected event* which would enable AEMO to put in place additional actions to mitigate the risk to the power system following such an event occurring. Given the documented historical impacts on the Queensland region following loss of QNI it's unclear to ERM Power as to why a request for a *protected event* has not already been submitted.

Costs of providing either FCAS or primary frequency response

The costs to a generator, or other supplier, of providing either FCAS or primary frequency response can at times be significant, depending on prevailing energy and FCAS price outcomes. A generator maintaining headroom for the provision of contingency raise FCAS or generating at lower output levels when providing lower regulation FCAS at times when the energy market price is above the providers marginal cost, forgoes margin that would otherwise be accrued. Similarly a supplier that maintains capability above minimum load to provide lower contingency FCAS or generates at higher output to provide raise regulation services at prices below marginal costs incurs a direct loss.

This represents the true cost of providing frequency control services. The revenue derived in the FCAS markets is provided to compensate the provider for the provision of these necessary services. AEMO's proposal to mandate the provision of primary frequency response without compensation will remove the economic signal for providers to provide this capability and instead maximise output in the energy market when positive margin accrues, and minimise to the lowest output possible, or de-commit the generating unit when a direct loss is incurred.

The imposition of mandated primary frequency response may also change unit commitment and de-commitment decisions where currently a generator with a portfolio of units may operate an additional unit to provide frequency control capability across its generation fleet in return for being adequately compensated for providing this service.

The requirement for mandated primary frequency response without compensation removes the necessary economic signal for the provision of these services. Absent the economic signal to maintain capability, and as set out in our appendix to this submission when discussing headroom capability on NSW and Victorian generators at the time of the Queensland separation event on 25 August, any mandated primary frequency response requirement would be ineffective when headroom is absent.

AEMO in its rule change requests have highlighted the increasing cost of FCAS over recent years[11], we believe that AEMO has failed to consider that during the same time period as FCAS costs increases, input energy costs for generators have also increased, which have flowed through to increased energy market price outcomes. These increased input costs have a direct impact on the costs of supply of FCAS, and increased the gross level of compensation to providers. However, the net level of compensation earned by historic providers may well have decreased and the economic signal has also resulted in additional providers entering the FCAS markets. Muting of this economic price signal by the introduction of mandated primary frequency response may deter new suppliers from entering the market.

The Undrill report

ERM Power notes the significant detail regarding power system frequency performance in the Undrill report attached to AEMO's rule change request. We note that the report indicates the possibility of undamped oscillations within the NOFB. It is uncertain if AEMO were aware or had observed such oscillations prior to the report being submitted. We note that Mr Undrill's work was necessarily time limited and was unable to apply deep mathematical analysis of the qualitative observations. We believe that in response to this report more thorough analysis by local experts to fully understand its nature, and the cross linkages between units' governors and secondary frequency control, which may be a cause of undamped oscillations, is warranted.

[11] Figure 8 page 22 AEMO Rule Change Request - Removal of disincentives to primary frequency response during normal operation

We are concerned that moving quickly to an aggressively tight frequency control dead band and mandatory primary frequency response as requested by AEMO is unprecedented in the NEM, or any other power system, and may result in unintended consequences with possible hunting between individual generating units. Such an abrupt change in system operating parameters would not normally be considered by any control engineer. Generally a significant change of this type is managed by a progressive reduction in deadbands, closely observed for unintended outcomes, to find the optimal outcome. If any change is to be made it should be undertaken via a gradual trajectory.

Comparison of frequency outcomes with other power systems

ERM Power notes the comparison of power system frequency outcomes with other power systems as submitted by AEMO in their rule change requests. We also note that whilst frequency outcomes in the NEM are wider than other power systems, the outcomes reflect the decision to widen the FNOB made by the Reliability Panel in 2001 on the recommendation of the then market operator, that from an engineering perspective, tighter frequency control was not required and could not be economically justified. The outcomes observed align with the request of the market operator which was based on a decision to reduce FCAS procurement costs.

ERM Power considers that if AEMO believe the current frequency outcomes no longer meet the technical engineering requirements for required power system frequency outcomes in the NEM, then AEMO as the current market operator has the obligation to request that the current FOS be reviewed and amended.

We support Delta Electricity's view that the AEMC Reliability Panel, through consultation with all stakeholders, should determine what that adequate quality of frequency control in the NEM should be and amend the FOS as required.[12]

ERC 0263 - Removal of disincentives to primary frequency response during normal operation

ERM Power does not support all the proposed rules changes as submitted by AEMO. Whilst some level of disincentive to supply primary frequency response in the current regulation FCAS causer pays calculation remains, due to the use of a centralised power system frequency input, and the risk of time delay in delivery of generator output SCADA data, this can be easily fixed by the use of local frequency data in the calculation.

The current regulation FCAS causer pays calculation ensures that participants who act to provide frequency control support within the FNOB receive a very low or potentially a zero causer pays factor. Participants that currently act to maximise energy output at all times which may be misaligned with their current dispatch target do so as the costs of paying a regulation FCAS penalty amount is lower than the cost of adjusting output to reduce this penalty amount. This is the most economically efficient outcome for such a participant. In the event that the regulation FCAS causer pays penalty amount increased to the point where it was now economically efficient to do so, the participant would adjust behavior as required to the new economically efficient equilibrium.

We believe that no barrier exists to participants finding their most economically efficient outcome and that AEMO's proposed rule change will not result in a change to the physical dispatch outcomes, or to power system frequency outcomes within the FNOB, but may act to artificially reduce the level of penalty payment to the detriment of consumers who pay the net costs of regulation FCAS following the subtraction of scheduled participants causer pays penalty payments. Consequently, we do not support any of the proposed changes to clause 3.15.6A.

We do however support the proposed change to clauses 4.9.4 and 4.9.8 to clarify that a scheduled or semi-scheduled generator operating in *frequency response mode* and as a result is varying from its *dispatch instruction* due to prevailing power system frequency outcomes is compliant with its *dispatch instruction*.

We also support the proposed change to schedule S5.2.5.11 that a scheduled or semi-scheduled generator may operate, but is not mandated to operate, in *frequency control mode*, at any time.

[12] Page 6 Delta Electricity submission to AEMC's Consultation Paper – Primary Frequency Response Rule Changes

As we do not support any change to clause 3.15.6A no additional subclause is required in clause 11.1.

ERC 0274 – Mandatory primary frequency response

ERC 0277 – Primary frequency response requirement

Whilst we thank Dr Peter Sokolowski and AEMO for the work they have undertaken in preparing their respective rule changes and believe the information contained within is of value, ERM Power does not support either rule change proposal on the grounds that as set out in our submission, the rule changes are not required.

We are of the firm belief that the design of the FCAS markets are adequate and remain capable of managing power system frequency under both normal operating and contingency conditions and the only impediments to the FCAS managing power system frequency as originally intended has been imposed by AEMO itself through the ongoing under procurement of FCAS and the requirement that regulation FCAS be physically delivered solely by AEMO's AGC system.

The proposed rule changes are inconsistent with good market principles. Whilst mandating primary frequency response may see it adequately supplied for a time, frequency control services like many other power system services on which no economic value has been signaled invariably declines, due to the lack of an efficient price signal to exploit the best technology for its provision. Invariably this will result in increased costs to consumers as forms of a regulated response to alleviate the shortfall is activated similar to that required for system strength and minimum levels of inertia services.

We would support a more preferable rule that amended clause 3.11.2 to clearly articulate that regulation FCAS may be supplied by primary frequency response or by the market operator's Automatic Generator Control System or a combination of both primary frequency response and the Automatic Generator Control System.

We would also support a more preferable rule that amended clause 3.11.2 to clearly articulate the methods by which contingency FCAS response must be provided.

We recommend a change to schedule 5.2.5.11 with regards to the minimum access standard or an amendment to clause 4.4.2 that inserts a requirement for a generating system to at all times provide a frequency control safety net function that acts to support power system frequency outcomes when power system frequency falls below 49.60 Hz or increases above 50.40 Hz and that this requirement apply to all existing and new generating systems.

We would also support the Commission placing consideration of these two rule change requests on hold, as set out by the Australian Energy Council in their submission[13], pending completion of the trial and research process that was envisaged by the Frequency Control Frameworks Review final report.

Conclusions

ERM Power does not support either the Mandatory primary frequency response or Primary frequency response requirement rule change proposals on the grounds that as set out in our submission, the rule changes are not required.

We are of the firm belief that the design of the FCAS markets are adequate and remain capable of managing power system frequency under both normal operating and contingency conditions and the only impediments to the FCAS managing power system frequency as originally intended has been imposed by AEMO itself through the ongoing under procurement of FCAS and the requirement that regulation FCAS be physically delivered solely by AEMO's AGC system.

[13] Page 5 AEC submission to AEMC's Consultation Paper – Primary Frequency Response Rule Changes

The requirement for mandated primary frequency response without compensation removes the necessary economic signal for the provision of these services. Removal or muting of this economic price signal by the introduction of mandated primary frequency response may deter new suppliers from entering the market and influence existing suppliers to exit.

We support the proposed change to clauses 4.9.4 and 4.9.8 to clarify that a scheduled or semi-scheduled generator operating in frequency response mode and as a result is varying from its dispatch instruction due to prevailing power system frequency outcomes is compliant with its dispatch instruction.

Notwithstanding our belief that the FCAS markets remain capable of meeting the challenges of effective and efficient provision of frequency control services, ERM Power also recommends that the Commission consider an additional tool in the form of a frequency control safety net provision. All generators, regardless of enablement for provision of FCAS, would be required to operate with a frequency control response service at all times to assist frequency restoration following a significant non-credible contingency event to within the FOS interconnected system stabilisation band of 49.50 to 50.50 Hz.

ERM Power considers that if the current frequency outcomes no longer meet the technical engineering requirements for required power system frequency outcomes in the NEM, then AEMO as the current market operator has the obligation to request that the current FOS be reviewed and amended. We support Delta Electricity's view that the AEMC Reliability Panel, through consultation with all stakeholders, should determine what that adequate quality of frequency control in the NEM should be and amend the FOS as required.

Please contact me if you would like to discuss this submission further.

Yours sincerely

[signed]

David Guiver
Executive General Manager - Trading
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Appendix A

25 August 2018 multiple non-credible contingency multiple region islanding event

As discussed in the Paper, no two power system disturbances are ever the same, and whilst AEMO has sought to compare the Queensland region islanding event on 28 February 2008 to the Queensland and South Australia islanding event on 25 August 2018, system conditions and the market operators response at the time of each event varied significantly.

The Heywood interconnector remained in-service at all times during the 28 February event. UFLS in New South Wales (NSW) and Victoria did not trigger until after the loss of the Heywood interconnector on 25 August event. The Heywood interconnector tripped due to the large amount of headroom on synchronous generators (683 MW) and the Hornsdale battery (138 MW) in South Australia which provided primary frequency control response to the QNI Tripping event, thus causing the Emergency Alcoa Potline Tripping scheme to activate.

At the time of the 28 February event, in NSW and Victoria, 37 large thermal units were in-service with 23 units available for immediate response to the event, with a total available headroom of 4,235 MW, plus an additional 6 units in-service in South Australia, with 5 of these units available for immediate response with a total available headroom of 548 MW. In total there were 28 units with available headroom of 4,783 MW available to respond to the 28 February event.

On 25 August, there were only 21 units in-service in NSW and Victoria at the time of the event of which only 9 had headroom totaling 235 MW available to immediately respond to the event. There were another 5 units plus the Hornsdale battery with headroom totaling 821 MW available in South Australia which was lost to assist the restoration of power system frequency in NSW and Victoria when the Heywood Interconnector tripped.

The small amount of available headroom in NSW and Victoria, in particular compared to the larger amount of headroom available in South Australia on 25 August is in our view critical information that was omitted from AEMO's final report.

With the loss of supply from both Queensland and South Australia and the small amount of headroom available on in-service generating units in NSW and Victoria, mandated primary frequency response on generators in NSW and Victoria would not have prevented UFLS activating during the 25 August event.

In Queensland on 28 February the Queensland power system frequency was restored to below 50.50 Hz in nine minutes, approx. 1 minute quicker than on the 25 August event. The faster restoration of the Queensland region frequency was assisted by;

- The quick changeover of the AEMO AGC systems to recognise the Queensland islanding event and to control frequency to the Queensland frequency reference point within 1 minute of the event. On the 25th August event this change was delayed until 9 minutes after the event. During that critical nine minute period, generators in Queensland continued to be dispatched by AEMO's AGC system to higher dispatch targets.
- The operation of the Rapid Generation Unloading Service (RGUU) scheme at Swanbank Power Station which removed 59 MW of output from Swanbank B3 unit (1.1% of Queensland demand) from the system 50 seconds after the trip of QNI. No RGUU or OFGS was available in Queensland on 25 August.
- The invoking of islanding constraints to provide accurate *dispatch instructions* to Queensland generation within six minutes of the event. On the 25th August event this change was delayed until eight minutes after the event.

All these factors combined contributed to the Queensland power system frequency failing to meet the FOS requirements by a total of eight seconds on the 25 August.

Whilst the AEMO final report for the 25 August event indicated that "*The QLD region remained in a satisfactory but not secure operating state for 68 minutes until it was resynchronised with the rest of the NEM, due to AEMO's inability to procure sufficient contingency FCAS in the islanded region*", it should be noted that the same outcome regarding an inability to procure sufficient contingency FCAS in the islanded region also existed on 28 February where the final report for that event indicated "*it can be concluded that the separated Queensland power system was in an insecure state from 05:43 hrs to 06:38 hrs on 28 February 2008 (i.e. during the period of separation)*" similarly until the Queensland to NSW interconnector (QNI) was restored approx. fifty five minutes after the separation event.

We note that the registered level of contingency FCAS capability in Queensland exceeds both the size of the largest load and the size of the largest generator, by a significant margin. We can only assume that the contingency shortfall arose during both separation events due to the issue of capability (headroom) to provide the service at the time of the event. The issue of a contingency FCAS (frequency response) shortfall which relies on headroom capability would exist regardless of mandated primary frequency response as the same headroom capability would be utilised for either contingency FCAS or primary frequency response.

It is also worth noting that during 25 August event, AEMO, despite being concerned about the secure operation of the power system, did not issue any clause 4.8.9 Direction(s) to any generators to operate in *frequency response mode* to either more quickly restore the power system frequency to the FOS or to improve the secure operation of the power system when AEMO considered that the power system was not operating in a secure state.

AEMO have also expressed concerns that the frequency deviation nadir in the Queensland region following the non-credible contingency event almost reached 51 Hz, which AEMO believe to be a critical frequency level for secure operation of an islanded Queensland region. We note that the containment band in the FOS for a non-credible contingency event is 52 Hz. We are concerned that if 51 Hz is a critical frequency level in the Queensland region for maintaining a secure power system, that no request to amend the FOS has been submitted to reflect AEMO's concerns in this area.