Ms Anna Collyer
Chair, Australian Energy Market Commission
201 Elizabeth St., Level 6
PO BOX A2449
SYDNEY SOUTH NSW 1235

(Lodged electronically) 4 February 2021

AEMC Frequency Control Rule Changes (Ref. ERC0263 and ERC0296) Directions Paper 17 December 2020

Delta Electricity operates the Vales Point Power Station situated at the southern end of Lake Macquarie in NSW. The power station consists of two 660MW conventional coal-fired steam turbogenerators.
Delta Electricity appreciates the opportunity to comment on the Directions Paper.

Delta Electricity supports reforms seeking to develop markets for both Primary Frequency Response (PFR) and Fast Frequency Response (FFR), but the latter ought to include for inertial response of rotating machines. The new services should be specified to permit adaptation and service provision from new or existing systems and not show bias against either in the development of the new markets.

Delta Electricity supports market solutions over mandatory rules as these drive the most efficient solutions and, at best, provide the right market signals for new services. Ultimate success in these endeavours is arrived at where market signalling is agreed, by the majority of NEM participants, to represent realistic valuation of the services.

Contingency Frequency Control Ancillary Services (FCAS) are dispatched to secure readiness in the NEM to contain deterioration in frequency resulting from contingency events. The value of contingency FCAS services should be associated closely to the benefits the services provide to the NEM and society in preventing worse system outcomes. As the services are continually procured but sparsely utilised, the cost considerations for these services ought to be quite distinct from continuously procured and utilised services such as PFR and Regulation FCAS. The sparse utilisation can also result in less awareness of performance inadequacy which only becomes apparent after full analysis of each contingency event and focused performance reporting.

A PFR service, by contrast, is continuously utilised and in much larger volumes then the present Regulation FCAS. The dispatch level and the assigned deadband of a PFR service continually influences the actual output of all Units on the system. For many large Units it also affects the performance of contingency services because the delivery systems are interdependent. The interdependency of the services on many large Units suggests to Delta Electricity that there is merit in finalising the eventual FFR after implementation of a PFR market.

However, a further revision to the Frequency Operating Standard (FOS) concurrently produced during the development of these new markets is also recommended. The Standard should be updated after determining the performance criteria for all necessary frequency control elements. The Standard should inform the FCAS service specifications. Adequate data monitoring and reporting by AEMO should provide transparent feedback information as to performance of each service and the overall performance of frequency control measured against the Standard. Adequate market signals and assigned value for these essential services should also encourage innovation, new entrants and investors in new and existing services.

Please find attached to this letter, the template provided by the AEMC with its directions paper containing responses from Delta Electricity.

Delta Electricity looks forward to the contributing further with the development of new markets that improve frequency performance for the NEM. If the AEMC wishes to discuss any aspect of this letter, please contact Simon Bolt on (02) 4352 6315 or simon.bolt@de.com.au.

Yours sincerely

Simon Bolt
Marketing/Technical Compliance

Attachments:

1. **AEMCs Stakeholder Submission Template – Delta Electricity**

AEMC

Directions paper – Frequency control rule changes

STAKEHOLDER SUBMISSION TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on specific questions that the AEMC has identified in the directions paper for the frequency control rule changes.

The rule changes discussed in the frequency control directions paper are:

- AEMO – *Primary frequency response incentive arrangements* (ERC0263)
- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)

This template is designed to assist stakeholders provide valuable input on the questions the AEMC has identified in the directions paper. However, it is not meant to restrict any other issues that stakeholders would like to provide feedback on.

Given the breadth of issues discussed in the directions paper, it is not expected that all stakeholders respond to all the questions in this template. Rather, stakeholders are encouraged to answer any and all relevant questions.

SUBMITTER DETAILS

ORGANISATION:		Delta Electricity
CONTACT	**NAME:**	Simon Bolt
	EMAIL:	simon.bolt@de.com.au
	PHONE:	02 4352 6315 or 0418 663 110

CHAPTER 4 – FAST FREQUENCY RESPONSE MARKET ANCILLARY SERVICE

Question 1: Section 4.5.3 – PROBLEM DEFINITION AND REFORM OBJECTIVE — FFR RULE CHANGE	
What are stakeholders' views on the problem definition and reform objective for FFR as set out in section 4.5.3 of the directions paper?	Regarding the third dot point regarding increasing inefficiency in market outcomes, Delta Electricity expects the decline in inertia over the next decade will become more apparent when: • synchronous machines retire – this is expected to have a large step change impact at each retirement. OR • during times of high intermittent generation dispatch at times of higher demand when larger (than usual) numbers of remaining synchronous machines out of service; It is not particularly apparent to Delta Electricity that each remaining synchronous machine will contribute less inertial reaction. If a rotating machine is in service but on low load, it still provides inertia. Planned outages of each remaining synchronous machine, in general, are not expected to increasingly occur in number or duration except perhaps in the months nearing each anticipated and reported retirement date. Therefore, it is perhaps relevant to suggest that the FFR reform timeframe should focus on schedules that result in implementation ready to meet scheduled retirement dates.

Question 2: Section 4.7.1 – FFR PROCUREMENT			
In relation to the discussion of potential procurement arrangements for FFR services in section 4.7.1 of the directions paper: • What are stakeholders' views on the pros and cons of establishing new FCAS market arrangements for FFR services versus revising the existing arrangements to incorporate FFR within the fast raise and fast lower services?	Procurement Arrangement	Advantages	Disadvantages
	Establishing new FCAS market arrangements for FFR services	Can be defined to target exactly what is theoretically required. If it can be coordinated well with existing FCAS controllers, the targeted new market can be specifically dispatched, tuned and used to fine tune inertia-like system reactions.	May need more complicated Rule changes. May produce more potential for uncoordinated reactions not fully controlled with all existing conventional controllers and which subsequently increases instability rather than reducing it.

			May impose cost related impacts on existing technology that cannot easily be modified to provide and compete for FFR remuneration. Another market that all participants have to observe, react to and manage adding to an already complex series of FCAS markets. Theoretical perfection in FFR response may not blend with other controllers. Multiple controllers with different objectives still need to be coordinated to meet the overall frequency control objective.
	Revising the existing arrangements to incorporate FFR within the fast raise and fast lower services	Simpler in implementation that could be performed by a revision to AEMOs MASS. Blending controller expectations to produce an overall frequency response outcome is more practically achievable and will more naturally coordinate. Many existing 6 and 60s proportional services are generally supplied from the same controllers and it is considered sensible to combine them into one service. The same may be	Resultant service may be limited in delivery by having to combine faster delivery from new technology in an economic dispatch that is combined with expectations from slower existing controllers. More challenging to accommodate all economic cost rationale within a combined "fast & FFR Raise/Lower" market services.

	<table><tr><td></td><td>true for the desired impact from proportional FFR.</td><td></td></tr></table>
• Do stakeholders agree that the existing arrangements for contingency FCAS provide an appropriate model for FFR market arrangements?	The existing market constructs requiring AEMO to procure contingency FCAS to satisfy the obligations bestowed upon them by the Rules to control frequency and to ensure the Frequency Operating standard is met are the appropriate model. However, the existing services specified by the AEMO MASS have, since inception in 2001, been more demanding of data capturing and theoretically preferred response calculations than being a technical description of the preferred service control block diagrams which would provide clarity, practical reasoning and the necessary engineering guidance and criteria to control design specialists as to what the frequency controllers are meant to be doing. A greater incorporation of practical control engineering advice into the specification is required even if the FFR is not an eventual inclusion and the latest review of the MASS by AEMO will provide opportunity for this improvement. Inclusion of a PFR market service and FFR into the MASS is considered possible but the overall objective must be the level of coordinated control that **the market is prepared to support in pursuit of the best technical quality with minimised security risks at the lowest acceptable cost for the services**. The present FOS was already being met prior to mandatory PFR and it remains unclear what the true actual costs of no FFR and wider PFR support may be except to say that it generally is accepted that the control was trending to poorer quality, less predictability of balance and greater potential costs resulting from non-contingent events. Mandatory PFR has over delivered in narrowing the overall frequency result to a tighter control band but has not addressed the increased variability in the second-to-second performance. A frequency standard which identifies the costs of all unwanted variability and guides the market as to the value in smoothing it is recommended.
• What are stakeholders' views on how each of the proposed procurement arrangements for FFR would interact with the arrangements for the existing contingency services?	<table><tr><td>Procurement Arrangement</td><td>Interaction with existing contingency services</td></tr><tr><td>Establishing new FCAS market arrangements for FFR services</td><td>Existing uncompensated inertial reactions and existing Fast services are already coordinated by nature of proportional controllers and the mechanics of spinning machines i.e., the governor reaction is coupled to the turbine and responds accordingly. Hence there should be no impact on existing machines from a fast service permitted from their own inertia</td></tr></table>

	<table><tr><td></td><td>capability from a new FFR market if one is designed to permit inertia.</td></tr><tr><td>Revising the existing arrangements to incorporate FFR within the fast raise and fast lower services</td><td>Including the FFR within existing fast raise and lower provides a more direct "coupling" of technical reactions with other services as long as the specification requires the coordinated delivery within the one service.</td></tr></table> However, in general and applicable to new FFR technology, simulated inertial reactions from new technology that are not adequately designed to specifically respond to local, intra and inter-regional synchronous machines, Automatic Voltage Regulators (AVRs) and governors may result in unusual interactions with and reactions from various synchronous machines. The reactions of conventional machines to emerging quantities of new technology could disrupt stability, instead of improving it, by the introduction of complex uncoordinated transient reactions. The emergence of and dispatch of large MW capacities of these controllers may require modifications to be required to components all existing machines.
• Are there any aspects of the existing contingency FCAS arrangements that should be varied for procurement of FFR services?	If FFR is to be included within the fast service, it should not be mandatory that each fast service have FFR capability that meets the technical specification eventually developed in the MASS. Many existing Fast services are directly coupled with the natural inertial reaction of a spinning machine suggesting common sense that inertia be permitted as a form of FFR. That reaction as it currently is should be "grandfathered" to be accepted without imposing inefficient delivery of standard technical information that is implied by the design of rotating mass of known dimensions and weight.
Question 3: Section 4.7.2 – FFR PRICING ARRANGEMENTS	
In relation to the discussion of potential pricing arrangements for FFR services in section 4.7.2 of the directions paper: • What are stakeholders' views on the pros and cons of maintaining the existing FCAS pricing arrangements for FFR services?	<table><tr><td>Advantages</td><td>Disadvantages</td></tr><tr><td>Limited reconfiguration to existing systems Levels the playing field to avoid faster but over-shooting performers from claiming better performance when they have actually</td><td>May result in disincentives and lack of FFR delivery if faster performers are not encouraged in some way.</td></tr></table>

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<tr><td>over delivered and suppressed market delivery from slower but correctly proportioned and compliant performers.</td><td></td></tr>
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- What are stakeholders' views on the potential pros and cons of incorporating performance-based multipliers into the pricing arrangements for FFR services?

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<table>
<tr><td>Advantages</td><td>Disadvantages</td></tr>
<tr><td>Allows one way of recognising faster performance in the compensation system.</td><td>Complexity of pricing methodology, settlement and audit.

Pricing with performance-based multipliers is not currently employed in the existing services and would therefore require incorporation and adoption in ALL FCAS services not just FFR.

Faster overshooting performance is not necessarily better or fair performance to be rewarded.</td></tr>
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- Do stakeholders have any other comments or suggestions in relation to the pricing arrangements for FFR services?

</td><td>The merger of FFR and Fast FCAS services and an acceptable use of pricing multipliers to support better performance or assign larger emphasis or a form of co-optimisation to the sub-service that is preferred at any given dispatch interval is one avenue of reform worth considering for FCAS. A similar system could also be designed and adopted for PFR Incentivisation by way of a merger between Regulation FCAS and a marketised PFR using a similar construct but perhaps different multipliers. The multipliers may depend on the amount of MWs that is required between the distinct services contained with the one service in any given dispatch interval. e.g., if the required amount of FFR and Fast service is considered to be equal in terms of MWs then the pricing multipliers could be 0.5 times "Fast & FFR" price for each sub-component. Similarly, if the amount of required PFR compared to Regulation FCAS is in a ratio of 9 to 1 of regulation FCAS then PFR could be assigned 90% of a combined PFR/Regulation market price. Whether these examples are appropriate depends on whether the amounts required of different sub-services in a combined service can always be coupled to be required in a proportionally based way. If the dispatch objectives and targets cannot be effectively coupled in modelling expectations, or more importantly, for the majority of usual dispatch, then it is likely that separated services will be required.</td></tr>
<tr><td colspan="2">Question 4: Section 4.7.3 – FFR COST ALLOCATION</td></tr>
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In relation to the discussion of arrangements for the allocation of costs associated with FFR services set out in section 4.7.3 of the directions paper: • What are stakeholders' views on the arrangements for the allocation of costs for FFR services?	The existing allocation for contingency services is simplistic but simplicity promotes efficiency in the market mechanisms if the basic premise remains generally correct for the majority of circumstances that generators pay for raising services and market customers for lowering services. Whilst the AEMC's directions paper is wishing to consider the allocation, the FFR Rule change, if used to consider a change, would extend such a change in allocations to all contingency services.
• Would it be appropriate for the cost of FFR services to be allocated in a similar way to the existing arrangements for the allocation of contingency FCAS costs?	Yes. Until such time as more defined rationale for pinpointing direct causers for all second-to-second frequency reactions the simple system used remains preferred. It is also considered possible that the existing FCAS design and the potential FFR add on, being largely designed around theoretically based expectations for what machines should do may actually be resulting in individual FCAS category causation due to over or under reactions from uncoordinated controllers including, on occasions, the AEMO Automatic Generator Controller (AGC). It is considered better identify and fix any lack of coordination between physical controllers first, then redesign the MASS to be more technically correct for how machines actually respond and then, when and if these are both completed, reconsider reforming cost allocations in more detail.
Question 5: Section 4.8 – ISSUES FOR CONSIDERATION - FFR	
Are stakeholders aware of any additional issues that the Commission should take into account in developing market ancillary service arrangements for FFR?	Delta Electricity is not convinced that fast tracking an FFR market into existence is urgently required before the end of 2021 or even before 2023 but does support consideration of one, including for inertial reactions of existing machines, in the overall redesign of FCAS following completion of reforms and implementation of systems that incentivise PFR in an efficient and effective way. The existing **contingency** FCAS services are not considered to be dysfunctional by Delta Electricity except in the following ways: • MASS specifications of the performance required: ○ focused on a complex assessment separating into distinct mathematical baskets the reactions of a common proportional controller using data measured and stored by data recorders and data measurement devices. ○ In a single proportional controller providing more than one service, its response is largely determined by the size of the frequency deviation but is also dependent

	on Network conditions which vary whether the disturbance is near or far from the Unit. ○ Mandatory PFR continuously in operation also retards the performance of interdependent systems depending on whether the PFR system is in the process of restoring frequency in the same or opposite direction to a sudden contingency service requirement. • Inadequate preparation and response-time reactions/adjustments for regional separations and no preparation for regionally based FCAS safety nets in the event of separation events. • Inadequate re-evaluations of load relief assumptions, used in the dispatch arithmetic, to cater for the transient emergence and growth of roof top solar system capacities on the demand side of the market that, in the review of frequency events outside the NOFB, appears to be able to produce N-2 (and growing) impacts due to over-sensitive inverter protection reactions that drop out large clusters of roof top generation when frequency events occur. See notes below on the staging and implementation of FFR
Question 6: Section 4.8.1 – VALUATION OF INERTIAL RESPONSE	
In relation to the potential arrangements for the valuation of inertial response described in section 4.8.1 of the directions paper: • What are stakeholders' views on the valuation of inertial response as part of the contingency services, including the proposed new FFR contingency services?	Valuation of inertial responses is more difficult than simply meeting Frequency Control objectives because the inertial reactions, if insufficient, substantially increase the risk of more non-contingency system events and, therefore, the risk of system collapse and system black. If a reasonable methodology is proposed that draws into the valuation the likelihood that insufficient inertia increases the risks of larger quantities of unserved energy and increases the risks of economic impacts from black systems, it may increase the value assigned to inertial responses and improve the market incentives for service providers of an inertia service. However, all Contingency Services are actually purchased as a means of curtailing risks of larger system disturbances and/or system black conditions and, viewed from this perspective, inertia fits in well as being a Contingency service and is also faster in application than the current Fast 6s services are.
• What are stakeholders' views on the current governance arrangements for contingency services; where the detailed service specification is determined by AEMO and documented in the MASS? (Is it appropriate for the NER to provide further guidance on how inertial response should be considered in	The Market Ancillary Services Specification (MASS) and the NER 3.11.2(b) should more directly state that the MASS purpose is to define the specification of control services that support the objectives of the Frequency Operating Standard (FOS). The FOS should also be referred to by any

the MASS?)	protection systems that fall outside the control expectations covered by the MASS and the MASS should also acknowledge the existence of all other protection systems that it is not specifying. More recent desires for frequency control, such as PFR and better quality of frequency second-to-second, which may assist an operator meet other obligations in its control of frequency, should be considered and included for in a FOS consultation process, allowing illumination of the relevant issues and a determination of the appropriate balance between economic and engineering risk. Outside of the frequency controllers specified by the MASS, there are still other protection systems for frequency conditions that the NEM operator and TNSPs have that protect the system for inadequate frequency control including protections designed to shed portions of market load to avoid system collapse. The MASS also requires revision to better inform control engineers in the design of control systems that provide the services. Delta Electricity recommends AEMO be encouraged to consult with industry control design specialist consultants to obtain the best technical advice on what the MASS needs to become a better technical guide to expert designers of frequency controllers. The economic and engineering objectives for frequency control should be fully contained within the Frequency Operating Standards and be referenced by the MASS and by AEMO in its dispatch of and reporting of FCAS performance so that technical designers and operators always understand that although better controllers with more complexity, faster and more damped response and a greater quality of steadiness are possibly able to be designed, only designs that result in the required frequency operating standard being achieved are required. An adequately defined standard, supported by adequately designed services, evaluated by suitably efficient monitoring and reporting that feeds information that guides operators in adjustments of assumptions and required dispatch quantities ought to be able to control frequency effectively to the required standard and, if not, provide suitable data and information as to how the standard needs revising to improve the outcomes.

Question 7: Section 4.8.2 – PRICE RESPONSIVE DEMAND FOR CONTINGENCY SERVICES

In relation to the discussion of arrangements for incorporating price responsiveness into the procurement of contingency services in the NEM set out in section 4.8.2:

- What are stakeholders' views on the potential pros and cons associated with the implementation of a "demand curve" approach to procurement of FCAS?

Advantages	Disadvantages
Would probably acquire higher quantities of services and improve service performance for truly contingent events.	Contingency services, whilst always prepared for, are less regularly employed as they await larger events so procuring more

		services for generally what is not utilised may not be efficient. Actual utilisation of the enabled contingency services is more likely to occur at times of energy supply or contingency service supply shortage and high prices. The demand curve bias as described may prepare the same quantities as are prepared for now in such conditions. Procurement of more services in low price times will not provide necessary frequency support at times when the services and energy supplies are in shorter supply and risks to system security are therefore greater. The effectiveness of contingency services delivery in each event that utilises the service is not directly coupled into the price and quantities being determined for the majority of dispatch intervals where no event actually occurs. Contingency services are already a form of reserve market procured in case a large disturbance occurs. Inadequate levels of procurement arguably sometimes occur due to technical assumptions such as adoption of a 1.5% load relief unchanged from 2001 to 2019, reduced to 0.5% in 2020 and possibly still too high.
• What are stakeholders' views on the priority of such a change to the market frameworks?	This is a low priority. A more significant issue is that theoretical assumptions that determine the levels of contingency service quantity in today's market may still be incorrect and the market obtaining insufficient levels of service to adequately cope with specific events.	
• If such an approach was to be implemented, what are stakeholders' views on the appropriate governance arrangements, including the potential oversight role for	The approach is considered less important than some independent technical appraisal as to whether the quantities of FCAS currently dispatched are placing the market at unnecessary	

the AER?	technical risk due to inaccurate assumptions and insufficient review and exposure of existing poor performance and performers.
Question 8: Section 4.8.3 – INTERACTION BETWEEN MANDATORY PFR & FFR ARRANGEMENTS	
What are stakeholders' views in relation to the potential interactions between new FFR arrangements and the Mandatory PFR arrangement?	The technology that provides contingency services is, on many large NEM Units, the same technology that delivers Mandatory PFR. Unless separately designed and independent services are to be introduced to provide FFR, it is expected the interactions between Mandatory PFR and FFR will be the same as the now continuous deployment of 6/60s proportional control reserves occurring as a result of Mandatory PFR deployment.
Question 9: Section 4.8.4 – IMPLEMENTATION AND STAGING FOR FFR	
In relation to the discussion of the implementation arrangements for FFR services as set out in section 4.8.4: • What are stakeholders' views in relation to the process for the implementation of FFR arrangements in the NEM?	Delta Electricity suggests that the timing of reforms that develop FFR as a new Contingency FCAS are interdependent with but **should be re-evaluated and determined (or redetermined) after,** the reforms that incentivise PFR have concluded and been implemented and that therefore FFR may be better proposed in this current determination as being necessary but recommended to be designed in detail following commissioning of eventual PFR solutions from, or hopefully before, June 2023. Many existing contingency FCAS service mechanisms utilise the same mechanisms as that which deliver mandatory PFR. The designs of all existing and future perceived actual contingency FCAS service mechanisms and the quantities required of them will therefore be potentially impacted by the PFR service eventually conceived and developed. The eventual PFR service may directly influence the dispatch amounts and required speed of response of all eventual Contingency responses. Actual contingency responses are required far more infrequently to that of PFR and Regulation FCAS responses and hence the design of the latter will have far more impact on FFR design than will FFR designs have on PFR. Delta Electricity supports consideration of FFR in FCAS MASS reform but is not convinced that the Rules need many alterations to facilitate such a reform. In its simplest reform, it is possible that AEMO and market participants need only be encouraged by determinations by the AEMC and the Reliability Panel to, at a future time, cooperatively redesign the Market Ancillary Service Specification and dispatch systems in a coordinated and appropriately time-scheduled technical roll-out. However, even before reforms to the MASS to include for FFR are fully detailed, Delta Electricity considers MASS revisions and Rule changes that adequately incentivises a balanced marketised

	version of PFR is a preceding reform to pursue to completion perhaps with some level of insight as to how FFR and existing contingency and regulation FCAS will interact with market efficient PFR.
• What are stakeholders' views on the potential need for interim or transitional arrangements as part of the transition to spot market arrangements for FFR?	Transitional arrangements may become necessary if the final implementation of FFR is delayed or needs to be adjusted due to delays in any preceding or interdependent reforms, such as the incentivisation of adequate PFR, which Delta Electricity recommends be implemented distinctly prior to finalising the details for the FFR and any subsequent contingency service MASS reforms.

CHAPTER 5 – PRIMARY FREQUENCY RESPONSE INCENTIVE ARRANGEMENTS

Question 10: Section 5.1.3 – THE ROLE OF MANDATORY PFR	
In relation to the discussion of the role for a mandatory obligation as part of the enduring PFR arrangements in the NEM, set out in section 5.1.3: • Do stakeholders agree that a mandatory PFR arrangement provides a valuable safety net to help protect the power system from significant non-credible contingency events?	The present mandatory PFR arrangement has narrowed normal operating frequency performance to well inside the NOFB. The tightness of control appears to provide services well in excess of the present prescribed Frequency Operating Standard and, at least, better than what Delta Electricity has records for what existed in 2007. Performance better than what was being delivered in 2007 and perhaps pre-NEM seems overly conservative. However, the Mandatory PFR has not necessarily produced steadier local frequency second-to-second, the steadiness of which is now complicated by more regular but not necessarily perfectly coordinated mandatory PFR reactions from the assortment of governing technologies, metrology systems and controllers. A mandatory wideband PFR that overrides inadequate automated dispatch outcomes is possibly required, but to Delta Electricity, this system may actually represent a protection system and not a control system. A mandated protection systems, if to be eventually determined for frequency, ought to be included for in Generator Performance Standards and not the MASS. Such systems may also need to necessarily be decoupled from automatic dispatch system targets previously seen to cause unchecked frequency conditions well outside the FOS expectation such as what occurred in NSW on Tuesday 28 January 2020 when frequency as high as 50.3Hz was held outside the NOFB for over 50minutes due to incorrect data and reactions from AEMOs AGC. This occasion highlighted how, if the AEMO AGC is in error, no amount of conventional FCAS service can adjust for the conditions but a wider band PFR protection system might.

• Do stakeholders agree that the narrow, moderate and wide settings for a mandatory PFR response band adequately represent the broad policy options for the frequency response band for Mandatory PFR?	The NEM operated without mandatory PFR from 2001 to 2020. It is arguable that a mandatory PFR Rule was required as a result of reactions from participants to overzealous policing of precise energy dispatch conformance, inadequate design and expectations of the original FCAS regulation service, inadequate market valuation and compensation for traditional primary frequency systems but, in Delta Electricity's opinion, apart from the above a definite contributing factor has been the growing dispatch percentage of intermittent generating sources on both the supply and demand sides of the NEM. A marketised PFR is considered feasible in either reforms to FCAS for regulation services or via some other method. A wider safety net mandatory PFR applied to all generators and also included in AEMOs AGC is considered to represent a practical protection system which could, using smaller response levels, precede and prevent the deployment of larger-scale protection systems, such as under frequency load shedding.
Question 11: Section 5.4 – PROBLEM DEFINITION AND REFORM OBJECTIVE — PFR INCENTIVE ARRANGEMENTS RULE CHANGE	
What are stakeholders' views on the problem definition and reform objectives for enduring PFR arrangements set out in section 5.4?	The objectives are reasonable, but some additional priority should be assigned to developing a new market service for PFR prior to other frequency control reforms due to the expectation that: 1. PFR will be continuously dispatched, 2. Required MW quantities of continuously dispatched PFR probably outweigh the existing quantities of regulation FCAS procured, 3. Projected increase in intermittent generation and subsequent increased inaccuracy in the supply/demand balance suggests PFR quantities will be required in increasing amounts to historical equivalents in past years when dispatchable generation was less intermittent and 4. The inter-dependence of the systems that currently provide continually dispatched PFR with systems that provide contingency FCAS services and may provide FFR if developed.
Question 12: Section 5.4.1 – ECONOMIC ANALYSIS OF MANDATORY PFR	
In relation to the discussion of the costs and benefits of Mandatory PFR arrangements set out in section 5.4.1: • What are stakeholders' views of the indicative curves for costs and benefits of Mandatory PFR with respect to the frequency response band settings, set out	The curve is a good focus point to help guide the NEM and, preferably the reliability panel, in settling once and for all what the PFCB should really be. The market tries to provide a balance between preferences ranging between extremes of expensive technical precision and risk-minimalised operation to that of inaccurate wider control of frequency that reduces accuracy of engineering calculations and expectations because nominal frequency is too often not actually 50Hz. However, if the costs of either are not well understood it is uncertain if the total costs at either end of the scale can accurately be

in figure 5.4?	plotted on the same curve with the same axis as the expected security benefits. If the total costs dwarf the actual estimated benefits then Low, moderate and high-cost comparisons become less relevant to examine. Should the Blue and yellow lines be represented on the same axis? It might be worth considering whether the aggregate system benefits are in general much smaller, similar or much larger than the cost representations. If the benefits are truly much smaller than the overall costs, then the least cost and perhaps widest control may be appropriate. If the benefits are much higher than the overall costs in any of the cost scenarios, it may be largely incidental and the tightest possible control desired. The issue is really about evidence of the necessity which, in thorough reporting of data measured against an appropriately determined standard, should drive any need for tighter or in fact higher quality of control.
• Do stakeholders agree that the frequency response band setting is a key variable for the determination of enduring PFR arrangements that meet the power system needs and are economically efficient over the long term?	The frequency band setting is a key variable and ought to be economically appraised and included in an eventual revision to the Frequency Operating Standard.
• What are stakeholders' views on the effectiveness of the exemption framework under the Mandatory PFR arrangement?	The framework is adequate. It is possible there are other less theoretical and specific exemption rationales but in application, from experience with AEMOs PFRR process, it is considered such specific rationales, if adequately explained would be considered by AEMO.
• What are stakeholders' views on the role that the allowance for variable droop settings plays in relation to the cost impacts of Mandatory PFR?	An aspect that may not have been fully understood by AEMO is that whilst particular machines have droop equations and what the paper describes as less aggressive droop responses for smaller frequency reactions required by PFR, certain technologies, such as coal-fired boilers and its supporting firing equipment have long time constants and in order to balance the operation of the boilers, firing systems are fed-forward to ensure the utilised (or underutilised) steam is adequately controlled in the boiler to prevent interruption and mechanical damage. In such systems, the boiler MW rates to maintain the Unit stability are subsequently several times larger than the droop reactions. Hence the reason that Units would prefer to adopt wider deadbands and reduce the necessity to react to achieve technically supreme frequency steadiness. Cost impacts need to consider that every reaction required from such equipment is costly and if some of it can be avoided to meet a less technically supreme quality standard, this will save fuel costs, smooth the reactions required by the unit and lengthen the life of such equipment by limiting fuel, flame, steam pressure and temperature variations.

• Based on the initial roll out of the Mandatory PFR arrangement to generators over 200MW, what are stakeholders' views on how the cost impacts of Mandatory PFR are impacted by the proportion of the fleet that is responsive to frequency variations?	The tightness of the deadband is one aspect and the costs are borne evenly if plant are on similar deadbands and droops with similar stored energy levels supporting raise actions. As stored energy levels are not mandated to support raise services, some level of disproportionality will be occurring with the present Mandatory PFR if any plants are not maintaining stored energy for PFR. Similarly, successful obtained variations may be skewing cost impacts on participants.
• What other considerations are there in relation to developing effective and efficient arrangements for PFR in the NEM?	The required standard and what is **truly measurable** in reporting performance as opposed to what is **predicted** from lesser performance. The latter is only a prediction. Actual performance and actual reactions in true system events should be assigned higher importance and relevance than predictions and be utilised in making the predictions. The quality of frequency control. Whilst frequency is currently being controlled within a tighter control band, it remains unsteady within that band which may not be controllable due to variability and predictability of intermittent generation on both the supply and demand side of dispatch considerations. The proportion of intermittency in dispatch is considered worthwhile in inclusion in determinations of FCAS service quantities. If intermittent sources have a higher causation per installed MW, then dispatch could be improved if it was adjusted for this observation to provide more FCAS service when higher percentage intermittent generation is dispatched.
Question 13: Section 5.5 – ADVICE FOR ENDURING PFR ARRANGEMENTS	
What are stakeholders' views of the Commission's proposed approach to obtaining advice to inform its determination of enduring arrangements for PFR in the NEM?	The AEMC is encouraged to prepare or ensure its independent advisers prepare their own independent trends and comparisons from frequency data obtained prior to and post mandatory PFR implementation. Delta Electricity maintains its own records and can demonstrate that the mandatory PFR Rule has delivered PFR and frequency control within deadbands tighter than that being achieved in 2007. If this is the case, then the Mandatory PFR is likely to be over delivering, costing the industry with its inefficiency as was predicted by many in the industry would occur in its adoption. It is not expected that AEMO will openly agree that it has done because AEMOs purposes are not necessarily based on meeting a defined standard but rather on avoiding "possible" conditions that might arise due to a myriad of causes other than just frequency control such as which occurred in events on the 25 August 2018 (protection system failures, AGC system reactions, inadequate operating reaction times to regional separation, lack of regional FCAS preparation, insufficient FCAS quantities due to inadequate dispatch assumptions).
Question 14: Section 5.6.1 – PROCUREMENT ARRANGEMENTS FOR NARROW BAND PFR SERVICES	

In relation to the discussion of potential procurement arrangements for narrow band PFR services in section 5.6.1: • What are stakeholders' views on three options identified for further consideration? a. Existing market ancillary service arrangements b. New market ancillary service arrangements c. New incentive-based arrangements for voluntary provision	Delta Electricity believes the Option A from table 5.2 of the directions paper is possible. In its direction paper, the AEMC has discarded this option. Delta Electricity therefore supports option b. of the options mentioned here.
• Are there any other options that would be preferable?	In its direction paper, the AEMC has already discarded previously conceived options due to determinations based on previous advice and information. It may be worth re-examining the information that informed the AEMC that the challenges of merging FCAS regulation and PFR are too insurmountable. FCAS Regulation and PFR work continuously on managing the small and, due to intermittency of some new technology on the generation and demand sides, increasing levels of variability. The Mandatory PFR has reduced the wider variations away from 50Hz to well within the NOFB but it has not produced a flat line 50Hz result. Delta Electricity believes this is due to the growing inaccuracy of dispatch from the increasing quantities of mismatched dispatch outcomes arising from constant and difficult to predict variations in sun and wind. Whether PFR is a new market or a merged market directly affects the overall complexity of the eventual solutions for this problem. Multiple markets that are not coupled well together or to energy dispatch to produce a desired coordinated outcome will possibly worsen the overall frequency situation considering that all have to also work with decisions and actions made by the AEMO's AGC. Of interest to this point is the fact that AEMO have, in the Mandatory PFR implementation, recently favoured FCAS Contribution Factor resolution over steadiness of actual system frequency suggesting AEMO now have less concerns than they did previously as to present risks to system security from inadequate frequency control.
Question 15: Section 5.6.2 – PROCUREMENT ARRANGEMENTS FOR NARROW BAND PFR SERVICES	
What are stakeholders' views on the arrangements for the pricing of PFR as described in section 5.6.2?	Delta Electricity estimates that the necessary amount of efficient PFR will be possibly as much as 10 times the minimum amounts currently dispatched for regulation FCAS and is projected to increase with intermittent generation dispatch percentages. Intermittent sources contribute 5 times more causation per MW under the existing contribution arithmetic. PFR helps with some aspects of control of this uncertainty

	so the delivery of it in appropriate quantities is expected to be continuously required in increasing quantities. Large quantities required in dispatch of a service that is essentially costly for generators to produce in terms of impact on plant wear and tear and in the foregoing of energy market capability (either lost opportunity to generate more MWs for energy due to reserved raising PFR or forced requirements to over generate due to reserved lowering PFR), will be expensive for the market to acquire and expensive if, as requirements may increase, adequate available supply becomes increasingly limited. The market needs to be prepared to price the service appropriately and signal strongly to engineering innovators and investors that the capability is essential and will be adequately rewarded.
Question 16: Section 5.6.3 – ALLOCATION OF COSTS FOR NARROW BAND PFR	
What are stakeholder's views on the allocation of costs for narrow band PFR services as described in section 5.6.3?	A "contributor pays" process can work but of immediate concern is that the present methodology was recently found by AEMO as dysfunctional in some way as a result of the mandatory PFR implementation. Such dysfunctionality needs more transparency and discussion with all market participants to uncover more clearly whether the AEMO AGC is inadequately configured and, as a result, is a more substantial contributor to frequency unsteadiness than previously thought. Interfaces with AEMOs AGC and each dispatched operating Unit could also benefit from collective coordinated discussions between AEMOs control engineers and local control engineers to uncover further causes of poor coordination in the automatic dispatch systems.
Do stakeholders agree that the any additional costs for narrow band PFR be allocated through the existing causer pays procedure for the allocation of regulation costs (or a revised version as described in section 5.9?	The existing system of contribution pays could be adjusted. Regulation FCAS, as currently dispatched, **does not act instantaneously** on a Unit's output (It could be reconfigured to by way of a redesign and hence be delivered almost as rapidly as PFR but at present it is not designed in this fashion; As designed by AEMO it is delivered through the energy dispatch controller and has the same level of cautious delivery as does energy dispatch). Because of this fact, it seems that with the development of a PFR market, it would be overreach and inappropriate for FCAS regulation costs to continue to be calculated over a 4s basis. PFR, in contrast to regulation FCAS, causes a instant reaction to local frequency variations on the machine's output. Therefore, a suitable analysis calculation, **based on the local machine frequency,** could better differentiate and assign the 4s-to-4s costs to PFR and remnant 5minute-to-5minute costs to Regulation FCAS.
Question 17: Section 5.7 – PATHWAYS FOR ENDURING PFR ARRANGEMENTS	

In relation to the pathways for enduring PFR arrangements set out in section 5.7: • What are stakeholders' views on the enduring PFR pathways?	Pathway 2 is preferred.
• Do stakeholders agree with the Commission's preliminary preference for pathway two? (the widening of the PFCB and the introduction of market arrangements for narrow band PFR)	Yes.
Question 18: Section 5.8 – FUTURE REVIEW OF THE FOS	
What are stakeholders' views of the Commission's proposed approach towards a future review of the FOS as part of the development of enduring PFR arrangements?	Delta Electricity supports this action as soon as possible to eventually incorporate the balanced engineering/economic objective for PFR.
Question 19: Section 5.9 – REFORMS TO THE NER RELATING TO COST ALLOCATION FOR REGULATION SERVICES – CAUSER PAYS	
In relation to the proposed reforms to the NER relating to the allocation of regulation costs, set out in section 5.9: • What are stakeholders' views on the proposal to allocate regulation costs on the basis of performance against system frequency as opposed to Frequency indicator (FI)?	PFR performance is at best measured using reactions to a machine's **local** frequency rather than system frequency but system frequency is preferred over AEMO's FI which is filtered and time-lagged which is more relevant to the slower secondary reactions made by the existing Regulation FCAS corrections.
• What are stakeholders' views on the proposal to align the sample and application periods for determination of causer pays factors and shorten the application period to 5 minutes, in line with the NEM dispatch interval?	A real time performance indicator, **if accurate**, is preferred. However, it may be too simplistic to expect accuracy and Delta Electricity's experience with the present contribution factor and the capabilities of Units, fuel variations and machinery suggests the current time periods are presently a good compromise that can expose consistently poor performance and encourage improved performance. Delta Electricity suggests this reform can remain on the work platform but perhaps take place at a later time after more experience is gained with how dispatch systems and PFR and further Contingency FCAS system reforms impact on the existing methodology. It is also relevant to note that Mandatory PFR has produced an impact on the existing contribution factor system so some changes may be required more urgently.
• What are stakeholders' views on the removal or shortening of the ten-day notice period for causer pays contribution factors?	Delta Electricity considers the ten-day notice period is suitable for factors assessed over the sample and application periods currently used. If these periods are shortened as is being considered in the directions

	paper and mentioned above, then the notice period may also need to be altered to ensure relevance in the latest factor.
• What are stakeholders' views on AEMO's proposal to pre-calculate seven sets of contribution factors including local contribution factors?	Delta Electricity does not see any benefit to a participant from AEMO pre-calculating what are essentially performance factors that are affected by usually less predictable events, either local OR remote to each participant, that cause frequency disturbances that possibly disrupt a Unit's response and its performance. Average numbers of events are possible to be determined from past performance, but past performance can suddenly be altered by maintenance actions that then significantly change what the actual factor would be compared to the factors calculated in advance by AEMOs proposed method.
• What are stakeholders' views of AEMO proposal to include non-metered generation in the residual component for allocation of regulation costs?	Delta Electricity considers that non-metered generation should be included as it quite likely contributes to FCAS causation from time to time.