13 August 2020

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Australian Energy Market Commission
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Dear Commissioners,

SYSTEM SERVICES RULE CHANGES (ERC0263, ERC0290, ERC0295, ERC0296, ERC0300, ERC0306, ERC0307)

EnergyAustralia (EA) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC's) consultation paper on System Services Rule Changes in the National Electricity Market (NEM).

EA is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. EA owns, contracts and operates an energy generation portfolio that includes coal, gas, battery storage, demand response, solar and wind assets. Combined, these assets comprise 4,500MW of generation capacity.

EA is dedicated to building an energy system that lowers emissions and delivers secure, reliable and affordable energy to all households and businesses. EA is, therefore, appreciative of the AEMC's efforts to investigate future NEM system services frameworks. Ensuring these frameworks are fit for purpose will be a vital enabler of a rapid and robust energy market transition.

The key points in this submission are:

- EA welcomes the intent of the AEMC's consultation plan to consult on, assess and develop system service options in an integrated, transparent manner given the overlaps and interdependencies with other Energy Security Board (ESB) and Australian Energy Market Operator (AEMO) undertakings.
- With that said, EA considers these rule changes can only be adequately assessed in light of the ESB's Post 2025 National Electricity Market Design (MD2025) reform. EA, therefore, suggests that final rule determinations are made only once this framework has crystallised. This is to ensure that compatible changes, efficient implementation glide paths and regulatory certainty is provided to underpin investor confidence.
- EA highlights that robust price signals for future system services are a necessary, but not sufficient, condition for capacity investment in the current climate. Risk mitigation and incentive mechanisms, such as long term contracting and hedging arrangements, also need to be considered given the scale and tenor of investment required. EA encourages the AEMC to discuss the investment

implications and their complexities with stakeholders before final rule determinations are made.

- Given the significant overlap and interrelationship amongst the rule changes, a rigorous cost-benefit analysis is required. This is necessary to establish the relative merits of each change against the other proposals and the costs and risks of maintaining the status quo. Changes should only be implemented where tangible and significant long-term value for customers can be reliably demonstrated.

- EA considers that a centrally coordinated procurement model for system strength, such as the one proposed by TransGrid, is likely to be a better solution for ensuring minimum system strength levels and reducing economic and regulatory inefficiencies. That is, rather than the current approach which sees solutions based on discrete and isolated network connection processes for new plant. EA notes, however, that there are many details to work through and more evidence is required to demonstrate that a more co-ordinated and centralised approach will overcome potential new entrant free-rider impacts, promote equitable outcomes for generators, and avoid inflation of Regulated Asset Bases (RABs) via network augmentation bias.

- EA does not consider the Delta rule changes should be progressed given their inherent weaknesses and inconsistency with the MD2025 design measures. EA also notes design challenges with the other rules proposed. It will need to be demonstrated that these can be overcome, and are consistent with MD2025 outcomes, before EA can unequivocally endorse them.

- EA does not consider that Operational Ahead Markets (OAMs) would be a useful or necessary component of any future system services framework. Lacking a substantive and compelling rationale, OAMs will only impose unnecessary costs and risks on market participants with little in the way of offsetting benefits.

- EA considers that further analysis of frequency issues, frameworks and rule changes are required to ensure the National Electricity Obligation (NEO) is met. This includes further deliberation on the status of the Frequency Operating Standards (FOS), incentives for the provision of primary frequency control and contingency frequency arrangements.

Responses to specific questions are provided in the response template below, and we would welcome the opportunity to discuss this submission further with you. Should you have any questions, please contact me via bradley.woods@energyaustralia.com.au or on 03 8628 1293.

Regards,

Bradley Woods
Regulatory Affairs Lead

AEMC

Consultation paper - System services 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 Consultation paper for the System services rule changes.

The rule changes discussed in the system services consultation paper are:

- AEMO – *Primary frequency response incentive arrangements* (ERC0263)
- Hydro Tasmania — *Synchronous services markets* (ERC0290)
- Infigen Energy — *Operating reserves market* (ERC0295)
- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)
- TransGrid — *Efficient management of system strength on the power system* (ERC0300)
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)
- Delta Electricity — *Introduction of ramping services* (ERC0307)

This template is designed to assist stakeholders provide valuable input on the questions the AEMC has identified in the consultation 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 consultation 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

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CHAPTER 1 – INTRODUCTION

Question 1: Section 1.2 & 1.3 – Current ESB & AEMO work relating to the rule change requests	
1) What are stakeholders' views on how the rule change processes should be integrated with ESB and AEMO work programs?	EA considers it is critical that system security work across all market bodies is consulted on, assessed and developed in an integrated and transparent manner. EA, therefore, acknowledges and welcomes the general intent of the consultation plan to evaluate interdependencies, track coordination and further consider consultation timelines in light of other Energy Security Board (ESB) and Australian Energy Market Operator (AEMO) developments. With that said, EA questions how this will work in practice. The AEMC has indicated that the rule changes will continue to be advanced over the remainder of 2020. This is to help inform the ESB's Post-2025 NEM Market Design (MD2025) options paper. This is due December 2020 or January 2021. However, the timeline in the consultation paper shows the Commission only beginning draft rule determinations from March 2021. It is, therefore, uncertain as to how much value the rule changes might add to the options paper. To be clear, EA agrees that *final* rule determinations should only be made once the future market framework is known with sufficient clarity. This is to ensure rule changes are compatible with the future framework and that efficient implementation glide paths result. However, it may be appropriate to advance the rule changes to draft status so that they can provide more value as an input to the options paper. For example, by providing more consideration of key technical details that might be otherwise overlooked when undertaking broader frameworks analysis. EA notes that such an approach would minimise the risk that similar issues are effectively consulted on twice. That is, once as part of various ESB Market Design Initiatives (MDIs) and then again later as part of the rule change process. Moreover, it could also help with investment certainty. That is, by providing greater and earlier regulatory clarity on potential rule impacts for businesses cases being developed in the interim. EA, therefore, encourages further consideration of the overall reform and rule change timetables.
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	EA considers the ESB's Renewable Energy Zones (REZ) consultation may bear relevance to this work, given the potential overlap with TransGrid's system strength rule change. The Australian Energy Market Operator's (AEMO's) Power System Frequency Risk Review (PSFRR) may also be relevant to the frequency related rule changes in this consultation.
Question 2: Section 1.6 – Timetable for the consultation process	
1) Do stakeholders have any comments on the proposed timetable for the system services rule changes?	Please see the answer to question 1 above.

CHAPTER 3 – APPROACH

Question 3: Section 3.2 & 3.3 – Three work streams: dispatch, commitment and investment	
1) Do stakeholders agree with the AEMC's approach to grouping the rule changes, at least for initial consideration?	EA considers this is a pragmatic approach to tackling most of the challenges common to each rule change. EA notes the AEMC's comments on the Hydro Tasmania rule change but disagrees that it is best considered as part of the system investment workstream. It is true that the Hydro Tasmania rule change has asset investment implications. But this is no more so than the Infigen's Fast

	Frequency Response (FFR) rule change which is also being considered under the system dispatch workstream. Given this, and the fact that the intent of the Hydro Tasmania rule change is to overcome dispatch inefficiencies arising from low levels of synchronous generation, EA suggests it is better considered as part of the system dispatch workstream.
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	No, as detailed further in this submission, there are many issues and complexities with each rule change that are not represented in Figure 3.1.
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	In April, the ESB provided a high-level scheduling and dispatch assessment of various system services as part of its Scheduling and Ahead Markets workstream (reproduced in Appendix 1). EA agreed with this analysis, namely that: • Energy, FFR, Frequency Control Ancillary Services (FCAS) and inertia could all be procured, delivered and dispatched in current spot market timeframes. • Operating reserves could be procured and dispatched from anywhere up to a day ahead to hours or minutes ahead depending on technological limitations. • Other services such as voltage control, system strength and System Restart Ancillary Services (SRAS) were less amenable to a market-based procurement and dispatch approach. However, to the extent that contracts were in place to procure the services, it would only be technological limitations such as start-up times that would constrain service delivery. It should be noted that this analysis presumes that each service is required and is not obviated by another service being procured. This may not be true in all cases. For example, with enough inertia, FFR and system strength, services in some regions such as Tasmania may not be required. In this sense, questions of optimal service timing would be redundant.

CHAPTER 4 – ASSESSMENT FRAMEWORK

Question 4: Section 4.2 – The system services objective	
1) Do stakeholders agree with the AEMC's proposed system services objective being used to assess these rule changes? If not, how should it be amended or revised?	EA agrees with the proposed system services objective. In particular, the requirement for robust market and regulatory frameworks that pair climate change adaptation and mitigation strategies with a flexible, technology-neutral procurement approach. EA considers this will facilitate and incentivise the development of the broadest range of solutions, both now and into the future. For example, by supporting both traditional, mechanical-synchronous solutions as well as emerging, synthetic, inverter-based approaches that could result from aggregated Virtual Power Plant (VPP) and Vehicle to Grid (V2G) technologies.
Question 5: Section 4.3 – The planning, procuring, pricing and payment service design framework	
1) Do stakeholders agree with the '4Ps' service design framework being used to assess these rule changes?	EA considers the service design framework is appropriate when paired with the system services objective and rule assessment principles.
Question 6: Section 4.4 – Principles for assessment	

1) Do stakeholders agree with the principles proposed for assessing the rule change requests? If not, should any principles be amended, excluded or added?	EA considers the principles are appropriate when paired with the system services objective and services design framework. With that said, EA offers the following additions for consideration to enhance the assessment framework: • **Liquidity** - liquid contract and hedging market arrangements must be preserved so risks can be managed effectively. • **Proportionality** – framework changes that have high implementation costs, or are expected to be lengthy and complicated to effect, should only be pursued where the benefits are also expected to be high. • **Post Implementation** – rule changes should be subject to a post-implementation review so that change value can be used to inform and prioritise future framework developments.

CHAPTER 5 – THE RULE CHANGE REQUESTS

Question 7: Section 5.1 – Infigen – Fast frequency response ancillary service market	
1) What are stakeholders' views on the issues raised by Infigen in its rule change request, Fast frequency response market ancillary service?	EA agrees with the issues raised by Infigen. AEMO's Renewable Integration Study (RIS) indicates that the frequency nadir from contingency events will occur earlier as system inertia declines. Further, that six-second contingency service will become increasingly ineffectual. In this context, consideration of faster frequency response mechanisms is appropriate. Despite this, EA considers the issues raised by Infigen are but one part of a larger, interrelated suite of issues pertaining to frequency provision and control in the NEM. These turn on the increasingly blurred line between the frequency services that should be provided as part of a market response, and those necessitated by generation connection standards. Recent determinations such as the Mandatory Primary Frequency Response (MPFR) ruling have sided with the latter approach. Tighter, mandatory frequency obligations and generator connection standards may provide more certainty and control of NEM frequency for the market operator. However, they impose costs on all participants and mute market signals for service providers that may otherwise result in more innovative and efficient solutions. These trade-offs need to be carefully weighed to ensure that the National Electricity Obligation (NEO) can be met. In this respect, EA notes that Infigen's FFR proposal is but one of several potential solutions that could be used to improve contingency frequency control. Others include mechanisms that could maintain or increase the general level of inertia, such as those proposed by Hydro Tasmania or TransGrid in the consultation paper. As detailed further below in the responses to questions 18 and 19, EA considers the Reliability Panel's Frequency Operating Standards (FOS) have a critical determinative role in guiding rule-making and operational investment decisions to ensure relevant frequency performance measures are set and met. It is, therefore, crucial that relevant rule changes relating to NEM frequency control and operation are considered in this context. This is so that the costs, risks and benefits of different approaches can be appropriately evaluated such that an optimal balance between efficient service provision and secure operation results.
2) Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?	EA considers that a change to the NER will be required to support an FFR market. That is, assuming it is deemed to be an optimal solution to the issues described above.

3) What are stakeholders' views on if there are any other issues or concerns in relation to frequency control in the NEM as levels of synchronous inertia decline?	EA has no further comment beyond those noted above and in questions 18 and 19.
4) Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?	Yes, as noted above, the Hydro Tasmania and TransGrid rule changes are two proposals from the consultation paper which could obviate the need for FFR. That is, by maintaining or increasing the general level of inertia in the power system. Other solutions may include changes to generator technical performance standards or the FOS to help meet contingency frequency requirements. However, as noted above, these must all be considered in light of the ESB's MD2025 reform. To the extent that a rule change is inconsistent with, or will be obviated by MD2025 changes, EA suggests they not be progressed. This is to ensure regulatory efficiency and minimise investment uncertainty.
5) Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?	To the extent that existing FCAS markets have been deemed compatible with 5-minute settlement by AEMO, EA does not see that there would be any difference for FFR markets.
6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	EA agrees that Infigen's proposal will provide a signal for a service not currently valued in the NEM. It might also provide a proxy mechanism to reward inertia in the absence of a formal inertia market. That is, by measuring frequency response in the sub-2-second timeframe following a contingency event and *not* excluding inertia. For existing synchronous generators, FFR could then be provided as part of the natural inertial response to frequency deviations. EA notes this approach would require changes to the FCAS Market Ancillary Services Specification (MASS), but also notes that it might help with incentivising generation to remain online when energy prices were below marginal costs during times of inertial shortfall. Despite this, EA questions whether such signals will be enough to drive efficient investment. The economics underpinning investment cases for grid-scale batteries and other assets that can provide FFR and inertia are already challenging. Further, it is unclear whether the relative, marginal economic benefit of procuring FFR compared with imposing constraints or acquiring inertia will result in sufficient procurement volume to underwrite FFR market development. In this respect, EA strongly encourages the AEMC to discuss the practical business investment case implications of all rule changes with stakeholders before final rulings are made.
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	In principal, EA supports the consistent application of causer pays framework to all FCAS services, including any new FFR. Precisely what these frameworks should look like going forward needs further investigation, however. For example, it may be that a double-sided, or separate raise and lower, causer pays approaches are more allocatively efficient. EA looks forward to providing further input into these discussions as relevant consultation occurs later in the year.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	EA concurs with the costs assumed in the Infigen rule change. Namely, those resulting from required changes to the NEM Dispatch Engine (NEMDE) and to AEMO and market participant trading, dispatch and settlement systems. EA notes there may also be further minor regulatory costs incurred. For example, those arising from consulting on and changing the MASS as mentioned above.
9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	Introducing a new service that is not currently valued will see additional cost to customers. Whether these will suitably offset costs that might otherwise be incurred in managing frequency via other means, in the absence of FFR, requires quantification. Even if net benefits could be established, however, it would not necessarily follow that FFR should be pursued. It may be that FFR is incompatible with the future MD2025 framework. Other options being considered in this rule change consultation might also obviate

	the need for FFR. It is, therefore, vital that a comprehensive Cost-Benefit Analysis (CBA) that considers all these elements is undertaken so that the NEO might be best supported.
10) Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?	EA has nothing specific to add beyond the points noted above and will address other issues that may arise as the consultation progresses.
Question 8: Section 5.2 – Infigen – Operating reserves market	
1) Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?	Although not explicitly valuing operating reserves, current NEM design has proved adequate for meeting the reliability standard to date. However, increasing penetration of Variable Renewable Energy (VRE), extreme weather events and the lack of insight and control over Distributed Photo-Voltaic (DPV) resources are increasing uncertainty in market conditions and operation. Whether new technology solutions such as battery storage, V2G and demand response aggregation along with improved forecasting and Distributed Energy Resources (DER) technical standard initiatives are enough to overcome these challenges remains an open question. To the extent that they are not, EA considers an Operating Reserves Mechanism (ORM) may be one tool for helping to address short term supply issues and meet the reliability standard. With that said, an ORM is but one of many other possible solutions that might be employed to address ongoing reliability issues. The Delta proposal raised in this consultation is an obvious example. However, more pertinent are the future reliability framework options being evaluated by the ESB under its Resource Adequacy Mechanisms (RAMs) MDI. These range from incremental changes to existing market elements such as increases to the Market Price Cap (MPC) to a complete market overhaul to institute a centralised capacity market. ORMs are a specific solution category being assessed as part of the RAMs MDI. Critical to all these options are considerations of investability. Unfortunately, in the current political and regulatory climate, a theoretically perfect framework that delivers robust price signals is a necessary, but not sufficient, condition for capacity investment. That is, appropriate risk mitigation and incentive mechanisms, such as long term contracting and hedging arrangements, are crucial to offsetting risks from ongoing regulatory and political uncertainty given the scale and tenure of investment required. EA, therefore, favours reliability solutions that can provide this certainty. In this sense, EA strongly encourages the AEMC to discuss the practical investment case implications of all rule changes with stakeholders. Further, that final rule determinations should only be made once the future market reliability framework is known with sufficient clarity. This will allow a comprehensive assessment of the costs, benefits and risks of this proposal compared with other alternate solutions, including the costs of not doing anything. Lacking such analysis, the risk of implementing an interim ORM that is incompatible with, or obviated by, the RAMs outcomes is increased. This would come at great regulatory, implementation and investment cost to market participants and should, therefore, be avoided.
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	Please see the answer directly above for a response to this question.
3) Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?	No. Per the answer above, EA considers that robust price signals are a necessary, but not sufficient, condition for investment. Risk management and incentive mechanisms, including long term contracting and hedging arrangements, are vital for mitigating political and regulatory risks given the scale and tenor of required investment.

4) How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?	EA contends that the answer to this question will turn on many design details yet to be decided through this and other consultations such as MD2025. Further, that even once these decisions are landed that extensive modelling, including behavioural trading impacts, will be required to quantify the potential impacts on existing markets from the proposed design choices. Although this may come at some cost in terms of both time and analytical resource, EA considers such modelling will be essential for ensuring that any changes are net beneficial from a NEM-wide perspective.
5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	Please see the answer directly above for a response to this question.
6) How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?	EA considers that the greatest competitive pressure will result when the number of potential service providers and technology types are maximised. In this sense, there is likely to be significant value in extending the call time for service providers to offer reserves such that less responsive generation plant can also participate in a reserves market. For example, a call time of four hours would still allow for a high degree of forecasting accuracy but would allow many more generators to participate.
7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	EA agrees with the factors discussed in the Infigen rule change. Most prominent amongst these are trade-offs and interactions between operating reserves, strategic reserves and spot market outcomes. For example, from inaccurate forecasting leading to increased risk of triggering scarcity pricing. In this sense, EA suggests it would be useful to look at the historical '+/-' Regional Reference Price (RRP) sensitivities that are published by AEMO for each dispatch interval. This is so that patterns and trends in reserves requirements over time can be identified to better inform whether, and to what degree, reserves are required in each region.
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	Per the response to question 4 above, EA considers that this could be possible depending on final design considerations. For example, it may be that an ORM undermines trading in the spot-market and undermines hedging liquidity such that long-term investment signals are eroded. As mentioned above, it is essential that detailed modelling is undertaken to assess the likelihood of these outcomes once final design elements are decided.
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	EA considers that establishing an operating reserves market will see costs incurred for changes required to NEMDE along with AEMO and market participant trading, dispatch and settlement systems. This is beyond the regulatory costs in designing the appropriate market and rule frameworks. Per the answer further below on cost allocation, in principle, EA supports the application of causer-pays or beneficiary-pays approaches to cost recovery wherever possible. Economic theory and real-world experience illustrate that these approaches typically provide the clearest and most robust operational and investment signals, which ultimately lead to optimally efficient outcomes. To the extent that this is not possible, EA considers some socialisation of cost is acceptable, subject to distributional and equity considerations.
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	EA considers there is a delicate balance to setting incentives and enforcement penalties to ensure reserves commitment compliance. Set too low, there is a risk of reserves reneging such that reserves are not provided when required with consequential deleterious impacts for market supply and security. Set too high, however, and conservative bidding is likely to lower the potential pool of resources available for reserves dispatch. Although this might increase the capacity available in the spot market, and thereby reduce the need for reserves, it could be that low pool prices see units decommit entirely thus impacting both markets. As noted above, the

	modelling of potential bidding practices in light of these design choices will be required to ensure no untoward or perverse outcomes result.
Question 9: Section 5.3 – Delta Electricity – Introduction of ramping services	
1) Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?	Consistent with the foregoing, EA considers that the need for ramping services are best contemplated via MD2025. EA notes, however, that ramping is not explicitly required under the proposed options in the ESB's Essential System Services (ESS) MDI draft report, being effectively mitigated by new services such as operating reserves and FFR. Even if an explicit ramping service was determined to be required, EA considers there would be several issues that would challenge the successful implementation of the Delta proposal. A first issue concerns investability. As noted above, robust price signals *and* risk mitigation mechanisms are both required to underwrite investment in new, dispatchable capacity. The Delta proposal would effectively mute the former and is silent on the latter. It is, therefore, hard to see the necessary stimulus to support service market development would occur. EA considers the efficient procurement of ramping services will also be difficult to achieve. This will inevitably turn on forecasting accuracy, both in terms of service required and participant response. To the extent that there is are errors in these forecasting processes, over or under-procurement may result with consequential impacts on market development and investment. A third issue concerns the administrative complexity and burden to compare promised performance against that which is delivered. This is not a task AEMO currently must manage and maybe particularly burdensome given the difference in response times, ramp rates and unit reliabilities of different generation plant. Aside from increasing resourcing costs to support the service, it also raises the question of if/what compliance measures would be required. Dependent on the design of these measures, the attractiveness of service provision may be reduced. Beyond these points, it is not clear that disturbance elsewhere in the market would be avoided. For example, by changing the comparative incentives to participate in other FCAS and spot energy markets. Although the Delta proposal might result in pricing a currently absent market service, overall net market benefits would need to be demonstrated. EA considers this would be highly unlikely given the problems identified with the proposal. EA, therefore, suggests that the proposal is not considered further as part of this consultation.
2) Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?	Per the response above, it is not clear that the Delta proposal would address price volatility without creating further disturbance elsewhere in the market. Even if it did, however, EA questions the wisdom of reduced price volatility given its implications for investability. In terms of alternatives, EA notes the ESS MDI draft report conclusions do not envision an explicit ramping service requirement if other service combinations develop. EA also highlights that the ESB's Unit Commitment for Security (UCS) mechanism would obviate the need for an explicit ramping market. That is, in giving the market certainty about what AEMO will do in the absence of any changes to pre-dispatch information before a given deadline, it provides a signal for the market to respond and quantification of what will result operationally if it doesn't.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services	No, per the foregoing, EA considers this is a significant drawback of the Delta proposal. That is, even if the requirement for a ramping market could be demonstrated.

thanks existing price signals and information provided through the PASA and pre-dispatch processes?	
4) How do stakeholders think a separate 30-minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?	As above, EA considers there is the potential for disturbance to other markets from this proposal. Whether from actual market activity, or changes in the behavioural responses of participants in anticipation of market activity. Modelling of potential impacts will be critical to ensure any proposed changes are in the best long-term interests of customers.
5) How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?	Please see the answer directly above for a response to this question.
6) How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes in both energy and FCAS markets?	In theory, allowing the greatest number of providers and technology types to participate will best support energy and FCAS market outcomes. However, this is assuming no adverse effects across or between ESS and related markets and excluding any currently unpriced externalities such as carbon abatement. As above, EA considers a comprehensive assessment of these elements and their interdependencies is best undertaken through the ESB's MD2025 work.
7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	EA considers that efficient procurement of ramping services will turn on forecasting accuracy. Both in terms of service demand and participant response. To the extent that there are errors in these forecasting processes, over or under-procurement may result with consequential impacts on market development and investment.
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	Consistent with the foregoing responses, EA considers there is the potential for adverse impacts on investability and market operation from this proposal. Detailed analysis and modelling of these concerns will be necessary to ensure no unintended consequences result. That is, assuming the proposal is advanced.
9) What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?	EA considers that the costs of this proposal could be higher than those noted in the consultation paper. As mentioned above, contrary to existing FCAS markets, this proposal would task AEMO with determining and monitoring ramping performance. This may prove burdensome given the number and complexity of the variables involved. In terms of cost allocation, EA agrees that cost recovery should be subject to existing causer-pays arrangements as with other FCAS markets.
10) What kind of incentive/penalty arrangements would be necessary to be confident the new 30-minute raise and lower FCAS products procured are available when needed?	As above, EA considers there is a delicate balance to setting incentives and enforcement penalties to ensure commitment compliance. Set too low, there is a risk of reneging such that ramping services are not provided when required. Set too high, conservative bidding is likely to lower the potential pool of resources available for ramping services provision. Detailed modelling of potential bidding practices in light of these design choices will be required to ensure no untoward or perverse outcomes result.
Question 10: Section 5.4 – Delta Electricity – Capacity commitment mechanism for system security and reliability	
1) Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to de-commit?	EA highlights that many of the comments made on the Infigen Operating Reserves proposal are also relevant to Delta's commitment mechanism. For example: • questions on whether an ORM is required, • whether it will incentivise and deliver efficient and robust, long-term reliability outcomes, • how it compares to other mechanisms being considered under the ESB's RAMs MDI, and

	• what effects it may have for existing markets and unit commitment, particularly given the risk trade-offs between incentives and enforcement penalties. Although these points could be considered as part of the RAMs MDI, EA considers that there are a number of weaknesses with the Delta proposal that should eliminate it from further evaluation. Most significant amongst these is the rationale for keeping non-peaking generators online. In providing a mechanism that promotes the continued operation of less flexible plant, the proposal would seem only to inhibit, rather than accelerate, the energy market transition. Aside from contravening the assessment principle of technical neutrality, this conflicts with recent developments that have sought to increase flexibility, contracting and competitive two-sided participation. For example, the Wholesale Demand Response (WDR) mechanism and Retailer Reliability Obligation (RRO). As explicated further in the ahead market section further below, EA does not agree that Operational Ahead Markets (OAMs) could be a useful or necessary component of any future ESS framework. Further, that they would impose unnecessary costs and risks on market participants, both in terms of one-off implementation costs and ongoing monitoring, trading and compliance obligations. As such, EA considers that further investigation of any rule change that requires an OAM to support it should be discontinued.
2) Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?	Consistent with the OAM responses below, EA highlights that an essential requirement in pre-dispatch is that bid forecasts are submitted in good faith. That is, they are accurate forecasts of how a market participant expects to bid into dispatch and are, therefore, considered to be firm by market participants at the time at which they are made. Like any forecast, these can change when new information becomes available. However, the good faith principle requires that pre-dispatch forecast bids are updated accordingly, as soon as possible, or face a market penalty. Indeed, it is this element that drives efficient price discovery and optimal market dispatch outcomes. In this sense, it is hard to see what better combination of flexibility, efficiency and confidence in operational outcomes could be provided to the market operator than from the existing pre-dispatch process. Beyond this point, it is simply not the case that greater operational aheadness will automatically entail greater commitment behaviour. Generators need to be able to hedge against risks that their ahead generation may be curtailed due to transmission outages, thermal derating, congestion and changes in weather forecasts. Mandatory, physical OAMs that apply severe penalties for non-conformance with an ahead schedule, or do not provide an avenue to amend scheduling for unforeseen events, will result in much greater bidding conservativism. That is, less commitment, not more. Even were these factors not part of an OAM design, incentives would be required to drive the use of a voluntary, financial OAM. The ESB has suggested increased risk management as a primary benefit. However, this notion has been considered and dismissed as recently as this year[1]. Lacking any other incentives, it is hard to see what benefit OAMs may add. EA notes this was the exact conclusion reached by the AEMC in its 2018 Reliability Framework Review: "If such an outcome occurred (i.e. participants did not provide as much capacity in a day-ahead sense), the benefits of a day-ahead market compared to the current NEM arrangements would need to be questioned" (page 168, Interim Report).
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?	Please see the comments on this issue in response to the Infigen proposal above.

[1] See the AEMC's Final Determination on Short Term Forward Markets.

4) How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?	Please see the answer above for a response to this question.
5) How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?	Please see the answer above for a response to this question.
6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	Please see the answer above, and comments on Infigen's proposal, for a response to this question.
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	Please see the answer above for a response to this question.
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	Please see the answers above, and comments on Infigen's proposal, for a response to this question.
9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	As above, EA considers there will be material costs from setting up an OAM to facilitate the Delta mechanism. This includes fundamental changes required to the pre-dispatch and dispatch engine, trading, settlements and reconciliation systems along with ongoing costs from monitoring, operational and compliance activities. It is difficult to see the purported benefits from the proposal will outweigh these costs.
10) What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?	Please see the answer above, and comments on Infigen's proposal, for a response to this question.
Question 11: Section 5.5 – Hydro Tasmania – Synchronous services markets	
1) Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services? a) Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation?	Conceptually, EA considers Hydro Tasmania's rule change proposal would be a viable, even elegant, option for procuring system services in the NEM. In particular, when enablement isn't limited to only synchronous sources. That is, EA understands that synthetic inertia and other sources that might be provided by batteries would also be supported by the Hydro Tasmania proposal in future. It would also seem to present an alternative, more straightforward mechanism to value constraints alleviation and send locational signals to market participants than the substantial reforms contemplated under the Coordination of Generation and Transmission Investment (CoGaTI) review. Practically, however, EA considers there are a number of challenges that would need to be overcome before the proposal could be implemented. Currently, NEMDE uses a linear programming methodology to solve for the least cost dispatch outcomes that satisfy all existing system security constraints. Although this is a secure, reliable and fast way to solve for a dispatch solution, it does have limitations.

b) Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?	For example, although non-linear, convex constraint formulations can be approximated by a linear approach and is used for things such as transmission stability constraints, non-convex constraints such as those relevant to system strength considerations are more problematic. Moreover, integer variables, such as commitment status cannot be solved for at all with a linear programming approach. Instead, a mixed-integer solution is required. The changes proposed by Hydro Tasmania would require just such a mixed-integer programming approach. That is, all combinations of Synchronous Services Generator (SSGs) circuit breaker status would need to be calculated to arrive at the least cost solution. Further complexity would be introduced from the need to optimise over multiple dispatch periods. That is, it is unlikely that start-up costs would be able to be recovered in one five-minute dispatch interval, so consideration of minimum run times would be required to incentivise synchronous generators to participate over multiple periods. EA is aware that mixed-integer algorithms have been used successfully for optimising energy and security dispatch outcomes overseas. However, EA is not aware of this being done in real-time as is seemingly contemplated under the Hydro Tasmania proposal. The technical viability of this approach would need to be established, given the extra costs that would be incurred if an ahead market mechanism was also required to support the proposal. Even if the technical bone fides could be established, EA considers this will not be sufficient grounds for supporting the change request. To fully implement the proposal would likely entail substantial modification to, or replacement of, NEMDE. Although this may allow other changes and benefits not contemplated by this rule change, e.g. it may support a move to dynamic loss factors and improvements to current constraint formulations, the costs and risks of such an undertaking are likely to be significant. Moreover, it is likely to take some time to implement given it is improbable that other priority NEMDE changes such as the move to five-minute settlement would be delayed to facilitate an earlier implementation. A rigorous assessment of these factors, including the costs and risks from a delayed implementation, against the proposal benefits will be required before EA could endorse it unequivocally.
2) Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what are these impacts?	EA does not consider that there would be material adverse impacts to other markets from the proposal. Generation units running in synchronous condenser mode can provide levels of inertia and system strength without producing energy. In this sense, they are unlikely to impact energy and contingency FCAS markets. It might be argued that those generators enabled under the synchronous services market would have an advantage in having their start costs covered to be able to bid lower in the energy market. However, this is no different to the situation now where thermal generators already online offer lower to avoid shutdown and start-up costs from decommitting.
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	Assuming the technical challenges detailed above could be overcome, EA considers that the Hydro Tasmania proposal would increase efficient price outcomes for synchronous services in the NEM. However, whether these were maximally efficient outcomes would remain to be seen. In the case of system strength, there is likely to significant locational aspect to service provision that precludes effective competition. To the extent that a generator was able to influence the likelihood of a constraint binding, or was the only option for relieving it, the economic efficiency gain may be minimal. That is, although the constraint might be avoided, representing a net gain for customers, service procurement may be at a cost only just below the ceiling imposed by the constraint and above a purely competitive outcome.
4) Do stakeholders consider the model set out in the rule change request to be capable of sending price signals sufficient to encourage new investment in synchronous capacity?	EA considers that the Hydro Tasmania request would be likely to provide robust price signals on the value of constraints alleviation via synchronous services procurement.

5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	EA considers being paid at bid, rather than the marginal the market-clearing price, would provide a strong operational incentive to provide synchronous services.
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	Yes.
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	Please see the answer to question 1 above for a response to this question.
8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	As mentioned in the response above, there may not be effective competition for some services such as system strength in all places, at all times. EA notes that this is not necessarily an outcome of Hydro Tasmania's proposal, however, but more a reflection of the current definitional and technical complexity surrounding the procurement of system strength in the NEM.
9) What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?	Further to the comments on question 1 above, EA considers there would need to be a rigorous testing and implementation approach to ensure any NEMDE changes faithfully represented current dispatch outcomes as well as facilitated the desired synchronous services market functionality. Beyond this, EA notes that there would be other regulatory change costs required. For example, updating the NER to include the new synchronous service generator registration category. EA considers the AEMC should provide a high-level assessment of how significant these changes might be to effect in order that the CBA for the rule change can be better informed.
Question 12: Section 5.6 – TransGrid – Efficient management of system strength on the power system	
1) Do stakeholders consider that TransGrid's approach addresses all issues related to system strength currently experienced in the NEM?	EA considers that a centrally coordinated procurement model for system strength, such as the one proposed by TransGrid, is likely to be the best solution for maintaining minimum levels of system strength to ensure power system security. As many stakeholders, including the ESB and AEMC have noted, the locational, binary nature of system strength means marginal pricing will be difficult to effect in all situations. This makes a more decentralised, market-based approach less practicable for ensuring secure operating levels. Other solutions, such as an access standard, would be unlikely to deliver the required minimum levels of system strength. Although mandatory service provision would remedy this deficiency, EA considers this would come at too high a cost in terms of economic efficiency. A centrally coordinated approach would have the advantage of building on the current frameworks and system strength procurement mechanisms. These include leveraging the current forecasting and planning processes, operational protocols, coordination with other markets services and regulatory oversight. Done well, this could improve economic efficiency via the delivery of system strength services in a timely, transparent and co-optimised manner. This could bolster investment outcomes, simplify connection arrangements and, ultimately, lower costs to customers. With that said, EA notes that there are many challenges with a centrally coordinated approach in general, as well as the TransGrid proposal in particular, that need further consideration. System strength levels change with energy demand and supply dynamics and

	occur over both operational (dispatch) and longer-term (investment) timeframes. The critical risk with a centrally coordinated approach, therefore, lies in the accuracy of the forecasting and planning processes undertaken by the central body. Any error will have the potential to result in over or under-provision of system strength, thereby leading to inefficient costs being born by customers. Inadequate service provision or underutilised assets are but two examples there. In this respect, the critical longer-term forecasting variables include the exit of coal-fired power stations and the connection of replacement renewable generation. EA acknowledges the work AEMO has completed to date in this area, e.g. with the Integrated System Plan (ISP) along with reporting improvements stemming from the transparency of new projects rule change. However, as acknowledged in AEMO's recent RIS, there is more required. For example, redeveloping existing pre-dispatch scheduling systems and improving modelling and forecasting of new technologies to better account for system security needs. EA supports these initiatives and considers that more information around the grid conditions under which voltage control and system strength will become problematic would also be useful. For example, consistent forecasting and review of fault level nodes to report on minimum synchronous dispatch scenarios. It is only through robust and transparent information provision and forecasting, developed in consultation with industry participants, that economic risks to customers can be minimised. A further issue concerns whether fault level is an appropriate metric on which to structure a system strength procurement framework. EA notes that even after several meetings of the AEMC's technical working group on system strength, no clear consensus on the best definition or metric for measuring system strength has resulted. The TransGrid proposal acknowledges that the implications of falling below minimum fault levels will be different in different locations. Mandating stable operation of generating equipment at short circuit ratio's as low as two would, therefore, seem to be an inefficient additional measure to address system strength concerns. As such, there is more investigation required to determine whether a fault level-based system strength standard could and should be applied. Further, whether this is best applied NEM-wide, on a regional basis, or at each fault level node. On this point, EA is aware that other international jurisdictions have approached system strength provision differently. For example, instead of fault level measurements, Ireland relies on a threshold number of online synchronous generators to ensure adequate system strength is provided. EA notes that if such an approach was adopted in the NEM, this would invalidate the need for the procurement framework proposed by TransGrid. EA agrees with TransGrid that the Do No Harm (DNH) framework has created barriers to the coordination and implementation of system strength solutions. Recent history is replete with examples of connecting generators undertaking system strength remediation, such as the installation of synchronous condensers, to address issues that will only persist for several years before being resolved by other planned transmission investment. EA, therefore, supports TransGrid's intent to reduce this inefficiency so that the NEO might be better achieved. Notwithstanding this support, EA considers more evidence is required to demonstrate that the TransGrid approach will overcome potential new entrant free-rider impacts, promote equitable outcomes for generators, and avoid inefficient inflation of Regulated Asset Bases (RABs) via any network augmentation bias. To avoid these outcomes, and maintain appropriate competitive tension, EA suggests that connecting generators should retain the right to institute their own system strength solutions. Transmission Networks Service Providers (TNSPs) should also be obligated to show that alternative solutions to network augmentation, such as system strength procurement from non-network providers, were not a feasible, lower-cost option. Beyond these concerns, EA notes that there will be many details to work through before a final rule can be endorsed. Amongst other things, TransGrid has proposed changes to:

	• The planning framework including changes to the network performance standard, • The generator connections, DNH and negotiations frameworks, • The system strength and inertia frameworks, • The definition of system strength, along with introducing • New TNSP, AEMO, Reliability Panel and generator obligations. Even supposing these changes could be agreed, EA notes there will significant regulatory impost and risks with implementing them. It is essential that these are factored as part of the CBA assessing TransGrid's rule change request.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	Per the response above, EA considers that a centralised approach is likely to be the best solution for ensuring adequate system strength. With so many details to be decided, it remains an open question as to how efficient the TransGrid proposal will be in practice. It is, therefore, vital that efficiency considerations remain prominent as the rule change is progressed.
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	EA notes that there are already many resources which can inform new entrant investment decisions. Examples include the Electricity Statement of Opportunity (ESOO), the ISP, TNSP Transmission Annual Planning Reports (TAPRs), the RIS, generator information guidelines, Marginal Loss Factor (MLF) forecasts and various Regulated Investment Test for Transmission (RIT-T) resources. Unless there is information not presently captured in these resources, but which would result from the TransGrid proposal, it is hard to see what incremental value there may be in terms of locational and financially signalling.
4) Do stakeholders agree that the 'do no harm' obligations should be removed? a) If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?	Please see the answer above for a response to this question.
5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	In principle, EA has no issue with this suggestion if it is implemented in a causer-pays fashion. However, it is unclear whether this is the intent in the rule change request. If not, it could lead to inequitable outcomes if costs are smeared across all generators in a locale or region, even if they were net contributors to system strength. EA, therefore, calls for clarity on this aspect of the proposal.
6) Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?	EA considers this should only be allowed in cases where there is a tangible, material net benefit for customers that could be demonstrated from TNSP ownership of the asset(s). For example, if purchasing a private asset to provide system strength was less than the cost of procuring system strength via other means such as contracting with synchronous generators. This would need to be closely monitored, particularly in respect of the RIT-T threshold, to ensure that this did not simply result in inefficient and unnecessary RAB inflation.
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	EA considers that the answer to this question will turn on how the many details of the proposal are settled. However, per the response to question 1 above, EA considers there is potential for inefficiency, network augmentation bias and free-rider issues that could result if done poorly.

CHAPTER 6 – SYSTEM STRENGTH

Question 13: Section 6.1 – Evolving the regulatory definition of system strength	
1) Do stakeholders consider that the AEMC's working description of the effects of system strength, and related problem description of system strength and its components accurately represents all elements of system strength, as experienced in the NEM?	Broadly speaking, EA considers the AEMC's working conceptualisation of system strength, its constituents and effects cover relevant elements. Given the general nature of the exposition in the consultation paper, however, it is not clear if some elements are assumed within existing categories or have been inadvertently excluded. Angular instability for synchronous generators and transient voltage oscillations following faults are two relevant examples. To the extent that these are included already, EA suggests these be made more explicit in future descriptions. To the extent they're not, EA suggests they be included as part of the AEMC's system strength conceptualisation.
2) If not, are there other components of system strength that the AEMC should include?	Please see the answer above for a response to this question.
3) What measures might be used to define system strength? Is fault level the only measure that can be used practically, or are other measures available?	Per the comments on the TransGrid proposal above, it is not clear that fault level is the best, or only, measure that could be used to underpin a system strength framework. EirGrid uses a minimum number of synchronous generators online in its approach to managing system strength. In Tasmania, so long as threshold levels of inertia are met, system strength is not a problem in most cases. In other NEM regions, fault ride-through settings of inverter based resources are more germane to system strength considerations than fault level. The relative merits of each approach, however, can only be evaluated once a robust definition of system strength and desired frameworks outcomes have been identified. In this regard, EA looks forward to further analysis of these issues during the upcoming system strength technical working group meetings.
Question 14: Section 6.2 – Mechanisms to provide system strength above the essential levels that are necessary for security	
1) Do stakeholders consider the centrally coordinated model, as proposed by TransGrid, is the preferable option for providing system strength above the essential levels required for secure operation?	As above, EA considers that a centrally coordinated model, such as TransGrid's proposal, is likely to be the best option for providing minimum levels of system strength. That is, assuming the design challenges and risks with the Hydro Tasmania proposal cannot be overcome and justified. If so, then a centralised approach is also likely to be the best option for procuring additional levels of system strength above minimum thresholds. The economic efficiency of this assertion would need to be demonstrated via CBA, however.
2) Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania to be the preferable option for providing system strength above the essential levels required for secure operation?	Per the responses above and below, EA considers there may be a role for the Hydro Tasmania proposal in procuring system strength if design challenges and risks can be met and justified. However, even then, it would need to be considered against the TransGrid proposal to demonstrate which is a better solution. That is, given EA considers it doubtful that it would be economically optimal to use both of them together.
3) Could a hybrid of these models be used to deliver system strength above the essential level?	Theoretically, this is possible. However, it is not clear that two different pricing approaches to procurement of the same service would be efficient or desirable. Notionally, it would seem to result in incurring almost all the costs and risks of implementing both proposals, but with only incremental benefits compared with implementing only one of these solutions. For example, if both could overcome the design issues raised above, then economic provision above minimum levels would also seem to be supported without another mechanism having to be employed. EA considers a robust CBA will be required to demonstrate which is a better alternative, both below and above minimum levels of service provision.

4) What do stakeholders perceive to be each model's strengths and weaknesses?	Please see the foregoing answers for a response to this question.
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	Changing access standards or mandating minimum system strength provision are two alternative solutions that have been raised in the AEMC's system strength review. EA does not consider that a mandatory service provision model would be appropriate for providing minimum levels of system strength, nor levels above this threshold. Being similar to the existing do no harm framework, it is hostage to the same deficiencies. That is, it is unlikely to facilitate the coordination and efficiency of service provision. In those areas where system strength is not, and is unlikely to be, an issue, the costs of mandating service provision will be a direct, deadweight loss of economic efficiency to NEM participants. A mandatory service model would place all costs of providing system strength on generators. However, strength issues result from the complex interaction of many demand-side and supply-side variables, many of which are not under the control of generators. Apportioning all costs solely to generators would, therefore, violate several principles considered necessary to maximise economic efficiency which EA supports. For example, both causer and beneficiary pays principles. A mandatory service model would also raise issues of economic equity between incumbent and future generators. For example, to introduce a mandatory service model on all generators would disadvantage existing generators who had made investment decisions in an era without having to provide system strength services. However, to place the mandatory service provision only on new generators would offer a competitive advantage to existing generators, potentially stymying new generation investment. An access standard model would have many of the same deficiencies as the mandatory service model. That is, generators would wear all costs of system strength provision despite not being a causer nor beneficiary in all cases. It would raise economic equity issues between new and incumbent generators. In applying costs to all generators, even in areas where system strength is not an issue, economic efficiency would also be inhibited. Moreover, an access standard would be unlikely to result in any meaningful long-term contribution to the provision of the three-phase fault level. Given these deficiencies, EA suggests neither model is considered further, whether alone or in combination with another option as part of a hybrid framework.
6) What do stakeholders perceive to be the biggest benefits and risks to introducing a mechanism to deliver system strength above the minimum levels required for secure operation?	EA suggests that constraints alleviation, increased hosting capacity, enhanced NEM resilience and investment in technologies to support such outcomes would be the biggest benefits from procuring system strength beyond minimum threshold levels. However, it would need to be demonstrated that such an approach was economically beneficial and didn't unduly discriminate amongst market participants. For example, where letting constraints bind was a cheaper alternative or where out of merit dispatch outcomes resulted.

CHAPTER 7 – OPERATING RESERVE SERVICE

Question 15: Section 7.1 – Requirement for a dedicated in-market reserve service, mechanism or market	
1) What do stakeholders see as the key drivers or changes in the NEM that could be addressed by introducing an explicit in-market reserve arrangement?	Please see the answers in the Infigen and Delta rule change sections above for a response to this question.
2) Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do	Please see the answers in the Infigen and Delta rule change sections above for a response to this question.

stakeholders consider the need to be permanent or transitional?	
3) How would an explicit in-market reserve mechanism or market impact stakeholders? What would be the key benefits and costs? Would it effect stakeholders' operational or investment decisions?	Please see the answers in the Infigen and Delta rule change sections above for a response to this question.
4) Do stakeholders see there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders see this as a separate need to an in-market reserve service?	EA considers that a fundamental driver of future capacity investment will be the presence of appropriate risk management mechanisms such as long-term contracts or other hedging alternatives. To the extent that these are missing from any operational reserves proposal, EA considers they will do little to incentivise and deliver efficient and robust, long-term reliability outcomes. EA, therefore, favours reliability solutions that can provide this certainty. As above, EA encourages the AEMC to discuss the investability aspects of proposed changes with stakeholders before final rule determinations are made.
Question 16: Section 7.2 – Achieving security and reliability using dedicated in-market reserves	
1) Do stakeholders have views on whether an in-market reserve market or mechanism should solve primarily for reliability outcomes and security outcomes second? Or can this be more effectively co-optimised?	In noting the many overlaps and interdependencies between the rule change proposals and the ESB's ESS MDI, EA contends that regulatory parsimony should be a preeminent consideration. That is, all proposals should be evaluated and prioritised in light of their ability to effectively and efficiently coordinate and address multiple problems. This will help ensure that minimum change will deliver the maximum possible benefits.
2) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM reliability framework? What are the policy design priorities for a new operating reserves arrangement that would deliver the reliability needs of the power system?	Please see the answers in the Infigen and Delta rule change sections above for a response to this question.
3) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM security framework? What are the policy design priorities for a new in-market reserve market or mechanism that would deliver the security needs of the power system?	Please see the answers in the Infigen and Delta rule change sections above for a response to this question.

CHAPTER 8 – FREQUENCY CONTROL

Question 17: Section 8.1 – Reforms related to the provision of synchronous inertia	
1) Do stakeholders consider that the issues relating to declining levels of synchronous inertia have been adequately and accurately described?	Yes.

2) Are there any other issues related to the provision of synchronous inertia that have not been adequately described?	No, although EA highlights there are links with system strength both in a physical and regulatory sense that are not mentioned. Firstly, higher inertia supports or may obviate the need for some system strength remediation. For example, as in Tasmania where, with sufficient inertia, system strength issues are also typically resolved. Secondly, the TransGrid rule change highlights that procurement of system strength may be most efficient when combined with the procurement of other services such as inertia and voltage control.
3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	Please see the answers to the Infigen and TransGrid rule change sections above for a response to this question.
Question 18: Section 8.2 – Reforms related to frequency control during normal operation	
1) Do stakeholders consider that the issues relating to frequency control during normal operation have been adequately and accurately described?	EA does not consider that all issues relating to frequency control during normal operation have been adequately and accurately described. Chief amongst these is the omission of the current status of the Reliability Panel's FOS. EA considers these standards play a key determinative role in guiding rule-making and operational investment decisions to ensure relevant frequency performance measures are set and met. It was, therefore, concerning that the FOS were not considered as part of the recent MPFR rule change. Moreover, that no quantitative assessment of the impact of MPFR on FCAS markets was undertaken. As a result, a temporary, obligation with unquantified impacts has been placed on market participants with further work required "…to understand the power system requirements for maintaining good frequency control"[2]. EA agrees with the need for more investigation. Tight mandatory frequency obligations and generator connection standards may provide more certainty and control of frequency in the NEM. However, they impose costs on all participants and mute market signals for service providers that may otherwise result in more innovative and efficient outcomes. These trade-offs, including impacts on other markets and investment signals, need to be carefully weighed to ensure the NEO can be met. Transparent, fit for purpose, and stable FOS will facilitate this objective by providing appropriate targets with which to incentivise or mandate the investment necessary to underpin secure frequency operation.
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	Please see the answer above for a response to this question.
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	EA supports further investigation of the causer pays framework. In particular, the incentives, cost allocation and remuneration settings that might apply to frequency control frameworks in future. In this respect, EA highlights that a double-sided causer pays arrangement, or separate raise and lower causer pays rules may be worthy of further assessment.
4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	As above, EA considers that a ground-up, first principles review of the FOS is required to ensure regulation services are fit for purpose as the power system transforms.
Question 19: Section 8.3 – Reforms related to frequency control following contingency events	

[2] System Services Rule Changes, p.67.

1) Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?	EA considers that there are other, broader considerations that are relevant to issues of frequency control following contingency events. Current rule change proposals and recent determinations are increasingly blurring the line between the frequency outcomes that should be provided as a market response, and those required as part of generation connection standards. As above, the costs, risks and benefits of these different approaches must be weighed so that an optimal balance between efficient service provision and secure operation results. As one example, it may be that Infigen's FFR proposal is the solution for contingency frequency control that best meets the NEO. However, EA notes that it could be obviated by other mechanisms that maintain or increase the general level of inertia, such as the Hydro Tasmania or TransGrid rule changes. Once again, investigation, analysis and assessment of solutions and the issues they are trying to resolve will be supported by clear and robust FOS.
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	Please see the answer above for a response to this question.
3) What are stakeholders' views on the best way to address the challenges to managing system frequency following contingency events, including reforms to value and reward FFR?	Please see the answer above for a response to this question.
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	Please see the answer above for a response to this question.

CHAPTER 9 – INTERACTIONS BETWEEN SYSTEM SERVICES

Question 20: Section 9.1 Technological and temporal issues for system service provision	
1) What are stakeholders' views on how the arrangements for system services can be developed, to best utilise the capability of both established, as well as new and emerging technologies?	EA considers that the proposed system objective supplemented with the design framework and the suggested expansion of the assessment principles, will facilitate and incentivise the development of the broadest range of solutions, both now and into the future. That is, via the combination of robust market and regulatory frameworks that pair climate change adaptation and mitigation strategies with a flexible, technology-neutral procurement approach.
2) Do stakeholders have any initial thoughts on how the arrangements for system services can be best coordinated over dispatch, commitment and investment time frames?	For comments on coordination over dispatch timeframes, please see the response to question three in the approach section. For commitment, please see the comments on the Delta capacity mechanism as well as the comments in the following section. In terms of investment timeframes, please see any of the response above that speak to the need for risk mitigants to support robust prices signals in ensuring investable outcomes.
Question 21: Section 9.2 – Aheadness and commitment	

1) Do stakeholders agree with the characterisation of arrangements for aheadness and commitment, including the potential benefits?	EA disagrees with the characterisation of aheadness and commitment and does not consider that OAMs would be a useful or necessary component of any future ESS framework. As explicated below, there is no substantive rationale for introducing OAMs. Any implementation would, therefore, only impose unnecessary costs and risks on market participants. EA notes the comments on the ESB's four reform options. As part of the technical working group on ahead markets, EA highlights that there is some support amongst stakeholders for the UCS mechanism to improve the interventions and directions framework. More notable, however, is the vigorous opposition from the majority of the technical working group to any other form of OAM arrangement. The ESB has stated that dispatch flexibility and coordination efficiency are hindered given synchronous generator start-up and ramping limitations. As the technical working group has demonstrated, this engineering argument is overstated. Not all synchronous plant is hostage to the same start-up and ramping limitations. Hydro generation and fast start gas-fired units are more responsive than traditional thermal plant in this regard. However, even thermal plant has strategies for minimising the impact of ramping and start-up limitations such as unit cycling and two-shifting. Looking ahead, the increased penetration of batteries and the development of new services such as synthetic inertia is only likely to undercut this argument further. The critical point concerning engineering, however, is that if technological flexibility to respond in an increasingly uncertain and variable operating environment is desired, an ahead market mechanism seems a peculiar choice of solution. That is, in providing a mechanism that promotes the continued operation of less flexible plant, an ahead market would seem only to inhibit, rather than accelerate, the energy market transition. The ESB has also promoted commitment, flexibility and transparency as further benefits of ahead markets. However, the ESB has overlooked the fact that these are already inherent and integral characteristics of the current NEM design. For example, an essential requirement in pre-dispatch is that bid forecasts are submitted in good faith. That is, they are genuine forecasts of how a market participant expects to bid into dispatch and are, therefore, considered to be firm by market participants at the time at which they are made. Like any forecast, these can change when new information becomes available. However, the good faith principle requires that pre-dispatch forecast bids are updated accordingly, as soon as possible, or face a market penalty. Indeed, it is this element that drives efficient price discovery and optimal market dispatch outcomes. In this sense, it is hard to see what better combination of flexibility and confidence in operational outcomes could be provided to the market operator than from the existing pre-dispatch process. Beyond this point, it is simply not the case that greater operational aheadness will automatically entail greater commitment behaviour. Generators need to be able to hedge against risks that their ahead generation may be curtailed due to transmission outages, thermal derating, congestion and changes in weather forecasts. Mandatory, physical OAMs that apply severe penalties for non-conformance with an ahead schedule, or do not provide an avenue to amend scheduling for unforeseen events, will result in much greater bidding conservativism. That is, less commitment, not more. Even were these factors not part of a mandatory, physical OAM design, incentives would be required to drive the use of a voluntary, financial OAM. The ESB has suggested increased risk management as a primary benefit. However, this notion has been considered and dismissed as recently as this year[3]. It is hard to see what benefits OAMs may add lacking any other incentives. EA notes this was the exact conclusion reached by the AEMC in its 2018 Reliability Framework Review: "If such an outcome occurred

[3] See the AEMC's Final Determination on Short Term Forward Markets.

	(i.e. participants did not provide as much capacity in a day-ahead sense), the benefits of a day-ahead market compared to the current NEM arrangements would need to be questioned" (page 168, Interim Report). Beyond these considerations, it is noteworthy that the ESB's own consultants to the ESS MDI, FTI Consulting, have highlighted that their draft ESS framework does not require an ahead market for implementation. Further, that there are many international examples of ESS being provided in real-time without issue. Other issues with OAMs, including their utility in a NEM context, have been adroitly dissected in Creative Energy Consulting's (CEC's) Scheduling and Ahead Markets Report. EA strongly encourages further study of this resource and its implications for these rule changes.
2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?	Further to the preceding comments, EA notes that there will be material costs and risks from setting up an OAM. This includes fundamental changes required to the pre-dispatch and dispatch engines, trading, settlements and reconciliation systems along with ongoing costs from monitoring, operational and compliance activities. EA does not see that the combination of these costs and risks can result in an outcome that will meet the NEO when weighed against the weak, incremental benefits discussed above.
3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	EA considers that the proposed UCS mechanism, improvements to forecasting processes, and capacity mechanisms that promote investability are other methods for improving power system operation in the face of increasing uncertainty.
Question 22: Section 9.3 – Cost recovery arrangements	
1) What are stakeholders' views on the appropriate approach to cost recovery for each of the system services discussed in this paper?	In principle, EA supports the application of causer-pays or beneficiary-pays approaches to cost recovery wherever possible. Economic theory and real-world experience illustrate that these approaches typically provide the clearest and most robust operational and investment signals, which ultimately lead to optimally efficient outcomes. Despite this, EA notes that it is not always possible to identify every causer or beneficiary in every instance. The actual cost or quantity of a required service may also be uncertain and based on projections at the time of investment or procurement. Where this occurs, EA considers some socialisation of cost is acceptable, subject to distributional and equity considerations. For example, even though specific beneficiaries, or benefit quantum, may not be able to be identified with perfect accuracy, it may still be demonstrable that some groups of recipients will be better off than others. In this case, smearing costs equally across all participants would then be inappropriate and inequitable.
2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	EA considers the principle of proportionality described above is germane here. That is, significant changes to market frameworks, systems, and processes should only be considered where cost recovery is significant or existing protocols are likely to lead to substantial inequity or inefficiency.
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	As stated above, EA considers it is critical that system security work across all market bodies is consulted on, assessed and developed in an integrated and transparent manner. EA, therefore, welcomes the general intent of the consultation plan to evaluate interdependencies, track coordination and further consider consultation timelines in light of other ESB and AEMO developments. In this sense, although EA supports the progression of these rule changes, EA considers that the *final* rule determinations should only be made once the future ESB market framework is known with sufficient clarity. This approach will minimise the risk that similar issues are effectively consulted on twice. That is, once as part of various ESB MDIs and then again later as part of the rule change process. Moreover, it could also help with investment certainty. That is, by

	providing greater and earlier regulatory clarity on potential rule impacts for businesses cases being developed in the interim. EA, therefore, encourages further consideration of the overall reform and rule change timetables to support these outcomes. In terms of the preferred implementation process, EA supports a balanced approach. That is, one that seeks to identify and coordinate the implementation of similar, higher value changes before lower priority changes are tackled. EA considers this is likely to avoid the implementation risks of a one-off, big-bang implementation approach where everything is done at the same time, and be more efficient than a progressive, piecemeal process which would see little scale benefits crystallised.
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper?	Please see the answer above for a response to this question.

Appendix 1: ESB System Services Dispatch Assessment

Method	Service	Scheduling and price formation	Degree of competition	Frequency of service need
1. Scheduled and priced in dispatch via co-optimisation	Energy	Favourable	Favourable	Favourable
	Existing FCAS	Favourable	Favourable	Favourable
	Operating reserve	Favourable	Favourable	Favourable
2. Scheduled in dispatch via co-optimisation	Additional frequency services (incl. inertial response)	Somewhat problematic	Favourable	Favourable
	System strength	Not favourable	Not favourable	Favourable
3. Not scheduled in dispatch	Voltage control	Somewhat problematic	Not favourable	Somewhat problematic
	System restart and load restoration	Not favourable	Not favourable	Not favourable