13 August 2020

Ms Merryn York
Acting Chair
Australian Energy Market Commission
GPO Box 2603
SYDNEY NSW 2000

Dear Ms York

Consultation Paper: System Services Rule Changes

Energy Queensland Limited (Energy Queensland) welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) in response to the System Services Rule Changes consultation paper.

The attached submission is provided by Energy Queensland, on behalf of its related entities, including:

- Distribution network service providers, Energex Limited and Ergon Energy Corporation Limited;
- A regional service delivery retailer, Ergon Energy Queensland Pty Ltd (Ergon Energy Retail); and
- Affiliated contestable business, Yurika Pty Ltd including its subsidiary, Metering Dynamics Pty Ltd.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact me or Charmain Martin on 0438 021 254.

Yours sincerely

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Energy Queensland

Submission to the Australian Energy Market Commission

Consultation paper – System Services Rule Changes

Energy Queensland Limited

13 August 2020

About Energy Queensland

Energy Queensland Limited (Energy Queensland) is a Queensland Government Owned Corporation that operates businesses providing energy services across Queensland, including:

- Distribution Network Service Providers, Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon Energy);
- a regional service delivery retailer, Ergon Energy Queensland Pty Ltd (Ergon Energy Retail); and
- affiliated contestable business, Yurika Pty Ltd (Yurika), which includes Metering Dynamics Pty Ltd (Metering Dynamics).

Energy Queensland's purpose is to 'safely deliver secure, affordable and sustainable energy solutions with our communities and customers' and is focused on working across its portfolio of activities to deliver customers lower, more predictable power bills while maintaining a safe and reliable supply and a great customer service experience.

Our distribution businesses, Energex and Ergon Energy Network, cover 1.7 million km^2 and supply 34,000GWh of energy to 2.25 million homes and businesses each year.

Ergon Energy Retail sells electricity to 738,000 customers in regional Queensland.

Energy Queensland also includes Yurika, an energy services business creating innovative solutions to deliver customers greater choice and control over their energy needs and access to new solutions and technologies. Metering Dynamics, which is a part of Yurika, is a registered Metering Coordinator, Metering Provider, Metering Data Provider and Embedded Network Manager. Yurika is a key pillar to ensuring that Energy Queensland is able to meet and adapt to changes and developments in the rapidly evolving energy market.

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1 Introduction

On 2 July 2020, the Australian Energy Market Commission (AEMC) published a consultation paper on system services rule changes (consultation paper). The consultation paper follows the submission of six rule change requests to the AEMC in relation to regulatory arrangements for the provision of services relating to reliability and security of the power system.

The rule changes discussed in the consultation paper are:

- Hydro Tasmania – Synchronous services markets;
- Infigen Energy – Operating reserve market;
- Infigen Energy – Fast frequency response market ancillary service;
- TransGrid – Efficient management of system strength on the power system;
- Delta Electricity – Capacity commitment mechanism for system security and reliability services; and
- Delta Electricity – Introduction of ramping services.

The AEMC is seeking feedback on the issues and questions raised in the consultation paper by 13 August 2020 to assist in assessing the proposed rule changes. Energy Queensland's comments are provided in sections 2 and 3 of this submission.

2 General comments

Energy Queensland welcomes the opportunity to provide feedback in response to the AEMC's consultation on the six rule change requests relating to power system security and reliability.

The Australian electricity industry has been undergoing significant and disruptive change over recent years, impacting all levels of the supply chain. A key component of the evolving energy landscape is the increasing dominance of renewable generation, primarily wind and solar photovoltaic (PV), and a corresponding decline in traditional coal and gas-fired generation. We understand that the growing penetration of distributed energy resources within customers' premises and of grid-connected variable and non-synchronous generation, in conjunction with the future retirement of coal-fired generators, will create significant challenges for the National Electricity Market (NEM), particularly with respect to maintaining the security and reliability of electricity supply. Energex and Ergon Energy Network are already actively responding to the technical impacts of these challenges, with one of our key forward planning strategies being to enable greater integration of new technologies into the networks while ensuring the ongoing reliability and security of supply. We acknowledge that there are a range of limitations and issues with the current frameworks that require immediate review and that the rate of industry development will necessitate regular and ongoing development of the rules for the foreseeable future.

Energy Queensland notes that the system services rule change requests are primarily transmission-focussed. However, as noted above, it should be acknowledged that increased embedded generation within the distribution network not only affects the operation of network assets but also the ability to maintain system strength and voltage regulation in both distribution and transmission networks. For these reasons, it is important that any changes to the existing frameworks should take into consideration embedded generation connecting within a distribution network and without direct access to the transmission network. With the continued growth in the numbers of generators connecting to Australia's networks, differentiating between generation in the transmission and distribution networks is becoming less meaningful.

The uptake of large-scale embedded generation on distribution networks is, in many cases but most particularly in Queensland, continuing at an unprecedented rate and volume. Regional and rural Queensland, in particular, have seen significant growth over the last three years in the number of large-scale generation connections, largely attributable to the State's high solar irradiance, the available and affordable land mass and Queensland's renewable energy target. If the 1.4 GW of large-scale renewable generation currently committed and connected to the Energex and Ergon Energy distribution networks continues to grow as forecast, the networks could have a connected renewable energy capacity of 8.3 GW by 2030. It should be noted that the 1.4 GW of large-scale renewable generation greater than 5 MW consists of 22 locations with less than 30 MW and 15 locations with greater than 30 MW. Further, the pipeline of large-scale renewable connections includes 34 locations with greater than 30 MW, and some systems as large as 180 MW.

While Energy Queensland is generally supportive of evolving system strength frameworks as proposed by TransGrid in order to improve the efficiency of new generator connections, we consider there are a number of issues that remain unresolved in the current proposal. For example:

- As described above, it is not clear how the proposed framework would apply to generators connecting below the transmission network level and how the subsequent coordination of functions between transmission network service providers (TNSPs) and distribution network service providers (DNSPs) to ensure a consistent and appropriate customer outcome would operate;
- Energy Queensland remains concerned about the proposed funding mechanism for system strength remediation with a move away from the current user-pays / 'do no harm' principles. While we consider there are benefits and efficiencies to be gained from a centralised approach coordinated by the relevant network, it is important that the costs do not automatically pass on to end-consumers to the benefit of a third-party generator. As part of their recent revenue determination processes, Energex and Ergon Energy received stakeholder feedback about significant concerns associated with the cost of electricity supply and the need to reduce costs. Therefore, in our view, where it is deemed efficient for networks to invest in system strength support, there should be a cost recovery mechanism from the relevant connecting generators in recognition of the investment and benefits. There may also be areas where it is not efficient for networks to invest or where generator proponents can more efficiently manage system strength themselves under a 'do no harm' approach and we therefore believe that this option needs to remain available in any final framework; and
- Energy Queensland considers there is a requirement for supporting economic assessment to be developed to justify the proposed approach from an efficiency and end-user perspective. While the logic presented by TransGrid is reasonable, given the unknown scale of potential investment associated with the rule change, it is important that there is a sound economic basis underpinning the change.

From a wholesale market perspective, Energy Queensland considers it is important that:

- The AEMC's consideration of the system strength rule changes are consistent with the Energy Security Board's (ESB's) post 2025 market design, particularly the system services and ahead markets design initiatives;
- The three proposed rule changes advocating that reserves and ramping services should be dispatched and rewarded in anticipation of a future need are carefully considered. Historically, these services have been satisfactorily supplied without being explicitly rewarded and at low cost to customers. The timing of the introduction of any rule change to reward reserves and ramping services also needs careful consideration to avoid unnecessarily incurring additional costs for customers before the changes are actually required;
- Concerns that the declining number of traditional, synchronous generators and new markets for system security services will not be sufficiently competitive and will create potential for the remaining traditional generators to exploit their power in that market are adequately addressed. There is a balance between timely change and changes

that are introduced too early or are poorly designed, and unnecessarily resulting in increased costs to customers.

Further, given the complexity of the matters under consideration and in order to provide a considered and meaningful response to consultation on these rule changes, Energy Queensland considers stakeholders would benefit from:

- Detailed economic and technical modelling and analysis of the solutions proposed in the rule change requests to confirm that they will achieve the intended outcomes and are the most efficient and cost-effective solution for end-use consumers. As generators do not pay a Generator Use of System charge, any associated network costs are passed on to the broader customer base through their network charges;
- An exploration of alternative options to address the system security and reliability issues currently being experienced in the NEM that may be more efficient and cost-effective;
- Greater visibility and understanding of the work being undertaken by the ESB to ensure there is alignment with the post 2025 market design. In this regard, it would be useful to have a roadmap setting out how all of the relevant initiatives proposed in this rule change package interact with the ESB's market design work (perhaps as an expansion of Figure 1 in the AEMC's consultation paper); and
- Sufficient time to respond to the issues under consultation.

Our feedback on the questions raised in the AEMC's consultation paper is provided in section 3 of this submission. We are available to discuss this submission or provide further detail regarding the issues raised.

3 Specific comments

Energy Queensland provides the following comments on the questions raised in the consultation paper for consideration:

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?	Energy Queensland is of the view that any proposed reforms that will impact upon market design or network investment should be coordinated with the post 2025 market design reforms to ensure that changes are aligned, and disruption is minimised during implementation. It would therefore be of assistance if greater visibility of the ESB's progress in developing the post 2025 market design was provided.
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	No comment.
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?	Energy Queensland considers that the proposed timetable for consultation should include sufficient time to enable economic modelling to be undertaken. Consultation timeframes should also allow stakeholders enough time to provide a considered and meaningful response to the complex issues under consideration.

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?	Energy Queensland is supportive of the proposed reforms being considered in a holistic manner.
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	No comment.
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	No comment.

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?	Energy Queensland is generally supportive of the AEMC's proposed system services objective which seeks to: *Establish arrangements to optimise the reliable, secure and safe provision of energy in the NEM, such that it is provided at efficient cost to consumers over the long-term, where 'efficient cost' implies the arrangements must promote:* • *efficient short-run operation of,* • *efficient short-run use of, and*

	• *efficient longer-term investment in,* *generation facilities, load, storage, networks (i.e. the power system) and other system service capability.*[1] However, while the proposed objective discusses the provision of arrangements at 'efficient cost', it is unclear from the consultation paper how the AEMC's assessment process will measure the benefits and costs to determine whether the proposed rule changes meet this objective.
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?	Energy Queensland has no objection to the use of the '4Ps' service design framework.
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?	We are of the view that 'minimising long-term costs for electricity consumers' should be included in the principles for assessing the rule change requests.

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?	As noted in Australian Energy Market Operator's (AEMO's) *Fast Frequency Response in the NEM* working paper: *FFR and inertia are different services. It is unhelpful to view FFR as a substitute for inertia. Although FFR has the potential to assist with frequency management at lower levels of system inertia, FFR and inertia are delivered via different physical mechanisms, and play roles that are not directly interchangeable.*[2] Therefore, it is not certain to Energy Queensland that having a fast frequency response market would necessarily address an inertia shortfall.
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?	We question whether a rule change is required to encourage efficient provision of fast frequency response services in the NEM following contingency events, or whether it may be more appropriate for AEMO to amend the *market ancillary service specification* to address the need.
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?	No comment.
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?	We recommend that modelling should be undertaken to determine the: • impacts of the primary frequency response changes; • improvements to the automatic generation control system; • likely make-up of generation as identified by the ISP; and • improvements to renewable generation forecasting. This modelling should demonstrate the nature of the future need and the potential fast frequency response requirements.

[1] AEMC, *Consultation Paper: System Services Rule Changes*, 2 July 2020, p. 23.
[2] AEMO, *Fast Frequency Response in the NEM Working Paper*, p. 4.

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?	Energy Queensland considers that additional analysis and exploration of other options is required before a judgement can be made on the efficiency and efficacy of the proposal.
6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	No comment.
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	No comment.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	No comment.
9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	No comment.
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?	No comment.
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?	No comment.
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	No comment.
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 comment.
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?	No comment.
5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	No comment.
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?	No comment.

7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	No comment.
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	No comment.
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	No comment.
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	No comment.
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?	Energy Queensland has observed and managed the impacts of variable renewable energy on NEM operations and the ramp from solar ceasing production for many years, particularly as it relates to voltage in the distribution network context. This has been at a low voltage level (i.e. managing the impacts of distributed and rooftop PV on the 11 and 22 kV distribution feeders) through to the sub-transmission network (i.e. managing the impact of grid scale renewable plant on the 66 kV, 110 kV, 132 kV feeders). As such, Energy Queensland can appreciate the challenge that this may cause at a wider system level with respect to matching generation and load, and the subsequent frequency impacts. However, Energy Queensland does not necessarily agree that a new market is required to specifically address this issue.
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?	We do not consider that a new frequency control ancillary services market is required. As Delta Electricity highlights in its rule change request, the ramping-off of solar in the evening and commencement of household loads is predictable. Therefore, we query whether analysis has been undertaken to examine the impact five minute settlement will have on disorderly bidding, and how forecast demand can be provided to participants in order to optimise the load / generation mix to avoid adverse impacts.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services thanks existing price signals and information provided through the PASA and pre-dispatch processes?	Without transparent scenario and economic modelling, it is unclear whether Delta Electricity's proposal will achieve the intended outcomes. In general, a market lever to correct an unfavourable condition will be less efficient than avoidance of the unfavourable condition in the first instance. Energy Queensland considers that alternative options should be explored.
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?	No comment.
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?	No comment.
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?	No comment.

7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	No comment.
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	No comment.
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?	No comment.
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?	No comment.
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?	No comment.
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?	No comment.
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?	No comment.
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?	No comment.
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?	No comment.
6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	No comment.
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	No comment.
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	No comment.

9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	No comment.
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?	No comment.
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? 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?	In principle, Energy Queensland agrees the model proposed by Hydro Tasmania could be a potential method for determining the most cost-effective generation dispatch. However, it is noted that non-synchronous generation can and does provide voltage control if required, so some nuance in how the market is developed may be required.
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?	In our view, care must be taken to ensure that a narrow view of what constitutes a 'synchronous service' is not taken, as there may be many technologies which can fulfil the required need other than an existing synchronous generator.
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	Energy Queensland notes that costed examples are included in an appendix to Hydro Tasmania's rule change request. However, we suggest that a wider cost estimation should be undertaken to determine the long-term outcome for end-consumers.
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?	More analysis is required to demonstrate the potential need, and therefore likely revenue, in a year (with forecast levels). This analysis will inform the market to make judgements on future investment. Long-term cost to consumers should be a deciding factor in making a rule change, before the benefit of profits from investment.
5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	No comment.
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	The locational aspect is not clear from the description of Hydro Tasmania's proposed rule change.
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	An opportunity is that more non-synchronous generating systems may be incentivised to provide voltage and frequency control.

8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	No comment.
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?	No comment.
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?	Energy Queensland suggests that it is not possible to address all issues associated with system strength across the NEM in a single rule change. However, we consider that the approach has merit, pending resolution of its application to distribution networks and other issues discussed below.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	Energy Queensland appreciates that the primary focus of the consultation paper is TNSPs. However, at present, DNSPs in Queensland have 1.4 GW of connected and committed asynchronous generation (consisting of 22 locations with less than 30 MW and 15 locations with greater than 30 MW), and an additional 2.6 GW in the pipeline (including 34 locations with greater than 30 MW). As such, the reforms proposed by TransGrid would not address system stability in the distribution network and would likely disadvantage generators wishing to connect to those networks, thereby limiting market choice. Energy Queensland does agree that the relevant network service provider is well placed to coordinate system strength planning.
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	Energy Queensland considers that a funding mechanism should be developed that ensures that costs do not automatically pass on to end-use consumers and that, as far as possible, the existing user-pays principles are applied to resultant network expenditure. This view is based on significant customer feedback provided to Energex and Ergon Energy Network as part of stakeholder engagement during the recent revenue determination processes associated with concerns around the cost of electricity.
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?	Energy Queensland remains in favour of retaining a 'do no harm' type framework, particularly in locations remote from strong system strength parts of the network as it may be the most efficient outcome for some connections. In our view, a connecting generator must not cause harm to existing networks and generators where costs are passed directly through to customers. We continue to see value in the full assessment (or similar) that EMT analysis provides, particularly in support of TransGrid's proposal for the generator to 'negotiate and meet its performance standards where they connect'.[3]
5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	Energy Queensland considers that generators should still be required to contribute towards system strength services. Fundamentally, it is our view that end-use consumers should not incur financial penalty. Without thorough economic and technical analysis, it is not clear quantitively that this proposal is the most cost-effective option for end-consumers. In theory, a purchase of a

[3] TransGrid, *National Electricity Rules change proposal: Efficient management of system strength on the power system*, 27 April 2020, p. 10.

	single, large device rather than several smaller devices should be more efficient and cost-effective. This is examined in the work undertaken by GHD and Powerlink in the *Managing System Strength During the Transition to Renewables* project which examined costs and locations of system strength increases in Queensland and potential impacts on distribution connected large-scale generation.[4] This work highlights that the centralisation of large system strength supporting plant and its size, location and scalability presents a risk in terms of stranded assets, minimal effectiveness for distributed generation and may lead to a 'blunt force' approach when other, more cost-effective alternatives are not explored. These issues need to be analysed and balanced in the final rule to ensure a fit-for-purpose approach.
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?	Energy Queensland highlights that TNSP-owned remediation may not assist with DNSP connections distant from the transmission network (or transmission node), as noted in the GHD/Powerlink paper,[5] thereby potentially causing increased connection costs for those proponents, and lack of choice for the market. Notwithstanding, we are supportive of efficient ownership of assets within the power system that support a high distributed energy future where consumers benefit.
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	The proposal does not cover distribution networks where an increasing number of generating systems ranging from 5 kW to 50 MW are being connected. Indeed, Ergon Energy Network has connected systems greater than 100 MW to its distribution network and is facilitating enquiries as high as 200 MW. Energy Queensland appreciates the implications of TransGrid's proposal which may reduce some risk and therefore reduce complexity of system modelling. At the same time, we caution against removal of analysis of the power system in an EMT package as, in our view, this is the best way to minimise future project phase risk. Rather, Energy Queensland would like to see greater availability of proponent EMT models to enable more transparency of system performance and thereby facilitate more efficient connections.

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?	No comment.
2) If not, are there other components of system strength that the AEMC should include?	No comment.
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?	No comment.

[4] https://arena.gov.au/assets/2020/05/managing-system-strength-during-the-transition-to-renewables.pdf
[5] https://arena.gov.au/assets/2020/05/managing-system-strength-during-the-transition-to-renewables.pdf

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?	Energy Queensland is generally in favour of this methodology to address a minimum system fault level. It is noted that coordination with DNSPs to identify likely distributed energy resource growth scenarios, and to identify locations of low and high fault levels, should be required. Energy Queensland also highlights that TNSP-owned remediation will generally not assist with DNSP connections distant from the transmission network (or transmission node), thereby potentially affecting those proponents differently.
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?	The model proposed by HydroTasmania is an outworking of the solution to system strength shortfalls. At present, there is no barrier to TNSPs or generators using this market-based approach to secure system strength services, and this model may be one such method.
3) Could a hybrid of these models be used to deliver system strength above the essential level?	In Energy Queensland's submission to the AEMC's discussion paper on *Investigation into System Strengths Frameworks* in the NEM,[6] we discussed the balance between the four models proposed by the AEMC. In that submission, we highlighted that a hybrid approach represented, in our view, the best balance between the challenges seen in transmission and distribution connections of registered generators. In a similar way, we are of the view that some components of each of the proposed models in this discussion paper has utility and could form part of an overall strategy of managing system strength in the network. It is our view that all proposed models can be used in the appropriate context, i.e.: • TNSPs or AEMO to centrally plan and procure system strength services, which may be market-based solutions, to maintain a minimum requirement whilst also considering the maximum fault level for an area based on plant limitations and economic augmentation options. • Generators to 'bring their own' system strength requirement that mitigates their impact on system strength status quo, which may be market-based or plant at their location, to facilitate their own efficient connection. • All new generating systems connecting to operate stably at low system strength levels, thereby reducing the overall network need for system strength. This could be an equipment standard which states that all plant must achieve stable operation at an appropriate floor for short-circuit ratio. This is important for efficient management of planned and unplanned outages, in addition to system normal operation. • A hybrid approach to provide positive incentives for original equipment manufacturers, networks, proponents and AEMO to continue to innovate to enable the future NEM. Energy Queensland considers the existing framework has had limited time to be effectively embedded in the context of other changes, such as the Power System Model Guidelines and Generator Technical Performance Standards rules changes. It is Energy Queensland's view that targeted review and improvement of the key issues and challenges associated with the current

[6] https://www.aemc.gov.au/sites/default/files/documents/eql_response_aemc_system_strength_consultation.pdf

	framework would be an expeditious way to progress the management of system strength. This approach would include: • A focus on model sharing provisions; • A review of minimum short-circuit ratio requirements; • Reinforcement of the existing role that the ISP has in coordinated investment (particularly to support strategic system strength reinforcement); and • Further coordinated education and support for consultants, developers and investors about system strength implications from a centralised source to ensure consistency and continued whole of market investment into understanding weak grid options for renewable energy integration.
4) What do stakeholders perceive to be each model's strengths and weaknesses?	For the centrally coordinated model, a minimum system level can be maintained. However, there is a risk of over-investment, or investment which does not address system strength needs for distribution-connected generation. For the market-based model, inefficiencies may result and there could be cost spikes at times without an appropriate minimum system level. However, a market-based model does have advantages in terms of flexibility. Energy Queensland is supportive of a hybrid approach to optimise use of the power system and minimise costs for electricity consumers. Having a hybrid model or a combination of models available also increases customer choice and ensures that the option pursued is the most efficient and fit-for-purpose.
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	It is proposed that there are certain 'quick wins' that can be implemented to provide benefit. Energy Queensland suggests that the AEMC could mandate model sharing between proponents. This would resolve some uncertainty for proponents if they were able to perform their own assessments to a reasonable level of detail prior to application. The intellectual property issues cited by manufacturers could be managed by 'black boxing' models, similar to what occurs for PSS/E models. Additionally, removal of some ambiguity in the current framework will lead to more consistency and thereby reduce churn and confusion.
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?	A key benefit of reforms is the ability to introduce the levers that drive innovation, so technology continues to adapt to a renewable-based electricity system.

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?	No comment.
2) Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do stakeholders consider the need to be permanent or transitional?	The in-market arrangement could be one method of managing the increasing penetration of distributed, uncontrolled generation. The permanency of this arrangement is dependent on factors such as ultimate control of small-scale generation through the implementation of dynamic operating envelopes and the ability to curtail if required.
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?	No comment.

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?	More cost analysis is required to determine which approach provides a better outcome.
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?	No comment.
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?	No comment.
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?	No comment.

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?	The increased complexity of the proposed reforms, and therefore the increased control and modelling, has not been discussed. While not directly part of the market, synchronous inertia plays an integral role in managing the future power system.
2) Are there any other issues related to the provision of synchronous inertia that have not been adequately described?	Technologies are emerging which can replicate synchronous inertia effects without use of a traditional rotating machine. As such, any future market design would need to be technology agnostic to allow for a need to be addressed rather than specify a particular service or technology.
3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	No comment.
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?	It is not clear that other initiatives, such as the mandatory primary frequency rule change and changes to small-scale PV operation, will be included in any benefit analysis of the reforms.
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	No comment.
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	No comment.

4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	No comment.
Question 19: Section 8.3 – Reforms related to frequency control following contingency events	
1) Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?	No comment.
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	The issues raised in the regulatory impact statement are acknowledged. In particular, we agree that the development of the largest credible risk when considering small-scale generator shake-off represents a key technical challenge.
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?	No comment.
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	No comment.

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?	No comment.
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?	No comment.
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?	No comment.
2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?	No comment.
3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	No comment.
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?	No comment.

2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	No comment.
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	The key challenge associated with implementing the proposed arrangements is the rapidly changing environment of the electricity system, and the impact of any post-2025 reforms. It is believed that any change that occurs prior to 2025 must, in principle, align with the post-2025 approach, otherwise risks to investment, existing and new generators, and networks, are too great. In addition, consideration of changes occurring in the small generation space (especially for distributed PV) must also be considered, given the large percentage of the generation fleet that distributed PV is forecast to make up (some 15 – 25 GW).[7] We need to ensure that the shift to any new reforms are well implemented, communicated and given adequate time to transition with appropriate engagement and education.
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper? 3)	The overall solution is likely to benefit from an incremental approach as unintended consequences from a wide variety of market reforms within a short period are difficult to predict. Staging of the reforms can help to ensure that other market changes, such as the wholesale demand response mechanism and five minute settlement, have had time to establish and influence investment prior to other mechanisms being introduced.

[7] AEMO Renewable Integration Study (https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris)