13 August 2020
Australian Energy Market Commission

Submitted online to www.aemc.gov.au

Submission on System Services Rule Changes Consultation Paper

CleanCo welcomes the opportunity to comment on the Australian Energy Market Commission's (the Commission) Consultation Paper on System Services Rule Changes.

CleanCo is Queensland's newest electricity generator. Our purpose is to deliver reliable clean energy solutions at a competitive price for Queenslanders. Our activities will help to improve electricity affordability, contribute to the achievement of Queensland's 50 per cent renewable energy target by 2030, support secure and reliable electricity generation, and create new investment and jobs in regional Queensland. We have a target to support 1,000 MW of new renewable generation by 2025 and we will achieve this by building, owning and operating our own assets and by investing in new renewable projects driven by others. CleanCo's supports rule and policy changes that support an affordable, reliable supply of clean energy to customers into the future.

Attachment 1 provides CleanCo's response to a range of key issues raise in the paper. To summarise:

(a) CleanCo prefers decentralised market-based solutions where practical. Centrally planned or provided models shift investment risk to customers, and so should only be pursued when there are clear benefits.

(b) The critical issue for both efficient use and investment in these services is setting an appropriate operating standard or expectation. The standard is the basis for investment – it is the signal that a service will be required and remunerated into the future. The ultimate market design, while important, is less critical.

(c) While they would reward existing generators (and perhaps help reduce the risk of early closure), none of the proposals appear investable. This may improve as the AEMC develops the operating standards for each. Investment signalling will also be aided by clearly linking liabilities/costs to parties (using causer pays where relevant), which may help develop secondary markets over time.

(d) The Infigen Fast Frequency Response and Hydro Tasmania proposals are incremental improvements to the NEM that should not await broader ESB considerations. However, the Infigen FFR should be adjusted to explicitly include inertial response – this adjustment can be reconsidered later if or when an inertia market is implemented.

We thank the Commission for the opportunity to submit on this process. If you have any questions about our submission, please contact me on rimu.nelson@cleancoqld.com.au or 0455 080 871.

Yours sincerely,

Rimu Nelson
Principal Advisor, Regulatory

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

ORGANISATION:		CleanCo QLD
CONTACT	**NAME:**	Rimu Nelson
	EMAIL:	Rimu.nelson@cleancoqld.com.au
	PHONE:	0455 080 871

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?	We largely agree with the proposal in the consultation paper. However, there may be a few interim or no regrets proposals that the AEMC could consider fast-tracking. The Infigen FFR and Hydro Tasmania rule changes could fit into this category.
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	Nil
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?	As above, there may be merit in fast-tracking any interim or no-regrets proposals. Otherwise the timetable appears appropriate.

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?	Yes
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	Yes
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	CleanCo prefers real-time markets where the conditions are conducive to strong competitive outcomes. To date, the real-time market has proved successful for providing most services in a timely and coordinated manner. Services like operational reserve and or inertia services may be suited to a commitment timeframe to maximise the number of generators that can participate in the market. Procuring on an investment timeframe typically shifts investment risk from generator/investor to customers – it may be required in some instances, particularly if there are highlighted gaps that require significant investment in the near term (for example, this may be necessary to rectify issues in North Queensland or Western Murray regions) .

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?	Yes

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?	Yes
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?	Yes

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?	CleanCo supports the intent of Infigen's rule change proposal but notes that implementation of an FFR market in the absence of an inertia market could reward participants for providing a synthetic proxy for inertia while not rewarding actual inertia. We consider that inertial response should be explicitly included and rewarded in the FFR (and potentially in the provision of other contingency FCAS markets) until a full inertia market is considered as part of the broader ESB process. This measure will allow the FFS changes to be fast tracked ahead of the development of an inertia market.
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?	There might be other/simpler options available. One option is for AEMO to adjust the MASS to ramp up the reward for earlier provision of FCAS in the fast raise/lower service and to allow provision for less than 60 seconds. This would not be a perfect option, but it would be quick/simple to implement and may work well as an interim measure.
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?	Without an appropriate market structure in place that rewards inertia, existing fossil fuel providers may close uneconomically early and there will be no natural or market-led replacement of inertia-providing generation/technology.
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?	Three additional improvements are required to reduce/manage the risk of contingency events: • as noted above, some form of inertia market should be progressed through the ESB's post-2025 review; • the AEMC should fast track an incentive framework for primary frequency response to ensure providers are rewarded for the services they provide. The existing mandatory provision is an incomplete solution; and • the AEMC should adjust the Frequency Operating Standard to reflect its views on an appropriate distribution of frequencies within the normal operating band.

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?	Yes. CleanCo supports aligning FFR with the existing contingency FCAS markets. This is a simple approach
6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	This is unclear. In the near term, the proposal would encourage the provision of FFR from existing generators/batteries. Over time, the market may provide enough certainty to deliver new investment, but more information about the required volumes and proven price outcomes would be required to understand this. However, to the extent that his service is an interim step to improve frequency performance while the ESB and AEMC consider a more fulsome framework that also encourages investment in inertia, driving investment in the medium/long-term may be less critical.
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	Apply in similar manner to existing FCAS. CleanCo also supports shifting to a real-time causer pays system for all FCAS rather than the delayed system. This would (a) better link the risk/reward of frequency/generation performance and (b) encourage secondary markets for FCAS.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	NA
9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	None that we are aware of.
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?	FFR should be understood/recorded as a proxy for inertia. While FFR can provide some of the benefits of inertia, it is not a replacement – it is reactive, and it is slower to respond. That is why we also support a market for inertia, and inclusion of inertial response in the design of the FFR mechanism in the interim.
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?	Yes. Having an operating reserve market could help ensure greater levels of generation are online at any point of time. One potential drawback of this mechanism is that it will not provide certainty of dispatch in a timeframe that allows most generators to commit and come online (as would be the case with Delta's capacity mechanism).
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	There are a wide range of options available, including a capacity market or a day-ahead operating reserve market; however, the Infigen proposal appears to be the simplest solution. Other market structures could be perceived to provide more certainty (but it is not clear that this is the case, or that this certainty warrants a more complex market).
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?	Efficient use of operating reserve services will depend on the volume/targets set. If the targets are set prudently, then the proposed market will deliver services well. It is difficult to see the proposed operating reserve market providing strong investment signals, but that will ultimately come down to the predictability of prices. While there were similar concerns that the FCAS

	markets would not drive investment, recent and proposed battery investments around the NEM highlight that price signals in the FCAS markets are in fact now leading to 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?	When plenty of spare capacity is forecast, shifting the availability of generation to operational reserve would tighten capacity in spot/FCAS. When tight capacity is forecast, then having the operational reserve market in place will bring additional plant online. For the contract market, some participants may be willing to offer higher contract volumes on the expectation that they will have additional plant online, but this may not lead to lower contract prices given potential for higher spot market prices.
5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	The intent of the operating reserve is to ensure more plant is online to protect consumers against unexpected changes in the market. This will ultimately come at a cost and need to be recuperated through prices. Some of this revenue will come through the operating reserve market, some will come through spot/FCAS, depending on how they are all optimised by AEMO and the offers of businesses. For the contract market, while generators may be willing to offer more contracts, the pricing outcomes will be closely linked to expectations of the spot market outcomes.
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?	Allowing AEMO to optimise across the markets is critical. This is one of the bey benefits of the proposed model.
7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	Unplanned outages, value of customer reliability, accuracy of load forecasts, variable targets based on the likely risk of a shortfall.
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	None that we are aware of, but it is up to the AEMC to determine whether this is the optimal mechanism for providing this higher level of reliability for consumers.
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	Cost allocation based on a causer pays approach makes sense where possible. The costs for the operating reserve market might be best attributed to consumers on the basis that the service is directly targeting improved reliability. More importantly, liable entities need to have transparency over their long-term exposures because this will help stimulate secondary markets and underwrite investment.
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	Same as existing FCAS markets
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?	It is not clear that the NEM has or will have a shortage of ramping capability, particularly following the implementation of 5-minute settlement in 2021. AEMO's Renewable Integration Study noted that further work was needed to understand the ramping requirements of the market moving forward. AEMO proposes to undertake this work throughout 2020 and 2021. That work should be progressed with priority and fed into the ESB post 2025 review.

	One of the benefits of a ramping market is that it could target support towards more flexible generators. We note this is a significant shift away from the existing pooled, single-price NEM, so further consideration of the potential impacts is required.
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?	It would likely help to reduce spot price volatility, but it is likely that this volatility will shift to the new FCAS market. More importantly, it would shift revenue to the new market which would ensure only flexible generators obtain rents relating to flexibility.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services than existing price signals and information provided through the PASA and pre-dispatch processes?	This depends on how much of the ramping rents shift from the spot market to the ramping market. In the near-term prices are likely to be relatively modest, but it is conceivable that they would become significant as the need for flexible plants with fast ramping capability increases.
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?	Shifting the availability of generation to a ramping product would tighten capacity in spot/FCAS. When tight capacity is forecast, then having the ramping product in place will increase the likelihood that generators with strong ramping characteristics are available when required.
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?	Unclear – this will depend on how the volumes are set and how it is optimised with spot/FCAS markets.
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?	Nil
7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	These would have to change daily based on the forecast need. Volumes should be optimised across energy, FCAS and ramping market.
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	Nil
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?	Unclear what the costs would be. Costs should be allocated via a real-time causer pays to the extent possible. Anything that is not attributed to causer pays should be funded by customers.
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?	Similar to existing FCAS
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?	While there are no/few examples of this to date, it may become a risk moving forward.

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?	The mechanism would likely work, but it is not clear yet that it is necessary or cost effective.
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?	Nil
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?	Nil
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?	This option would shift costs from the spot and FCAS markets to the new capacity market. On this basis, spot and FCAS prices would likely reduce. Further modelling is required to consider whether total costs would increase or decrease. On balance, consumers are likely to pay more when capacity is scarce or if the market operator is too conservative. The former is to be expected in a competitive market – higher prices are the signal for further investment. The latter requires close consideration of costs and benefits to consumers from improved reliability.
6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	Nil
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	Nil
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	Committed capacity (operating at MSOL) would displace cheaper energy or renewable energy, which raises a range of cost and equity concerns. AEMC would have to be comfortable that the benefits from the capacity mechanism outweigh these concerns.
9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	Nil
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?	Nil
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?	Hydro Tasmania's proposal is not a replacement for a synchronous services or inertia market. However, it is a simple and low-cost optimisation of the NEMDE algorithm that will reduce unnecessary curtailment and improve outcomes for consumers.

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?	
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?	It seems unlikely. AEMO would ultimately be able to optimise across the markets to find the lowest cost outcome and, unlike the Infigen and Delta proposals which essentially carve out generation into other markets, the Hydro Tasmania proposal is about getting more services online and providing services where it makes sense for consumers.
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	Yes – this methodology appears likely to efficiently price synchronous services. Under this model, costs would be allocated to customers, which may be appropriate. The efficiency of these costs will relate to the volume determined – if the volume is too conservative, the costs will be too high.
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?	Nil
5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	Nil
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	Nil
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	Nil
8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	Nil
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?	Nil
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?	The TransGrid proposal covers many of the key issues surrounding system strength, particularly related to connection of new generators.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	CleanCo acknowledges the system strength-related challenges that a range of participants have faced in recent years and agrees that a more proactive approach to system strength has merit. The challenge is how to achieve this in a manner that does not shift all risk to consumers. It is appropriate for the TNSP

	to have overall responsibility for system strength planning and provision. However, the AEMC should consider whether there are alternative options that could streamline/simplify/clarify the connection process without altogether removing responsibility for system strength from incoming generators.
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	On balance this is likely, but more detail on how the proposal would be operationalised is required. This approach, combined with the ongoing work on REZs, could significantly improve cost and timeliness for connections located in the areas where the TNSP wants to encourage new generation. That said, it will be important to maintain appropriate expectations in terms of timing/approach for connection applications elsewhere in the network, where connection may be more challenging but the location is attractive to potential new generators for other reasons – in these instances, proponents should not be required to wait for TNSP planning/regulatory processes (but they should be required to cover the cost of the connections and any relevant system strength upgrades).
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?	Do no harm is a good intent but has proven almost unworkable in some areas. The fast pace of change in the sector has led to continually shifting goal posts for potential generators. The AEMC should consider whether a simplified version is possible, where generators are responsible for fixing any system strength issues based on a first pass of the PSCAD modelling, with any later change being the remit of the TNSP and/or future connections.
5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	Some level of cost and benefit sharing is appropriate, but it should be closely linked to that generator's impact (both positive and negative) on system strength.
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?	This should be open for negotiation with existing owners. The TNSP should be able to make an offer based on a prudent cost. It should then be up to the existing owner to determine whether to retain or sell the asset.
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	Nil

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?	Yes
2) If not, are there other components of system strength that the AEMC should include?	Nil

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?	Nil
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?	CleanCo prefers a decentralised market-based model where it can work. This is on the basis that market-based approaches will typically innovate and find lower-cost options, and investment risk is borne by asset owners. For system strength, centralised planning is likely required, but decentralised provision is preferred. Under a centralised provision approach, consumers wear the risk of over investment and/or stranded assets. As such, a centralised provision model should only be proposed if analysis clearly illustrates that the potential benefits of a centralised approach (economies of scale, better coordination and planning etc.) outweigh the higher risk and potentially higher cost to customers.
2) Do stakeholders consider the decentralised, market-based model proposed by Hydro Tasmania to be the preferable option for providing system strength above the essential levels required for secure operation?	CleanCo prefers a decentralised market-based model where it can work. This is on the basis that market-based approaches will typically innovate and find lower-cost options, and investment risk is borne by asset owners. Under a centralised approach, consumers wear the risk of over investment and/or stranded assets. For system strength, centralised planning is likely required, but decentralised provision is preferable.
3) Could a hybrid of these models be used to deliver system strength above the essential level?	Yes, there could be provider of last resort rules to allow the TNSP to step in if the market is not providing services to a high-enough standard or at a low enough cost. Alternatively, there might be opportunities for TNSPs to make non-regulated investments and bid them into the decentralised markets (albeit that would raise a range of challenging ring-fencing issues).
4) What do stakeholders perceive to be each model's strengths and weaknesses?	As above.
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	Nil
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?	This might be an appropriate option within REZs where there is a pipeline of upcoming projects. It would provide a more resilient system and may streamline generator connections as the system strength buffer would reduce the granularity of modelling required. In terms of risks, system strength challenges to date have required bespoke solutions depending on the location, scale and technology of generation connecting to the grid. The specificity of the solutions makes over-provision challenging and potentially more costly in the absence of a clear pipeline of projects.

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?	The perceived lowering of reliability stemming from the shift from traditional generators to VRE
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?	Some form of reserve is expected by consumers and governments. To the extent there will be a reserve then incorporating it into the broader market structure will provide a more efficient outcome for consumers.
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?	Government – there would be an in-market target that could be used to increase reliability where perceived necessary Consumers – transparent, competitive and optimised energy markets allowing lowest-cost provision Generators – clear targets/standards to drive investment
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?	Not clear at this stage. We see it as a separate service which would shift the cost/risk of commitment from generators to consumers. The AEMC would have to determine that this cost/risk is outweighed by other benefits to consumers (e.g. perhaps it could lead to lower prices in the real-time markets from having more kit online).
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?	Nil
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?	Nil
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?	Nil

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?	Nil

3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	While FFR can provide many of the benefits inherent in synchronous inertia, it is not a perfect substitute. FFR is still delayed in comparison to inertial response and requires active measurement/calculations and changes in output. That said, particularly with ongoing investment in batteries, FFR has the potential to provide far greater total response in future, so its contribution to retarding frequency excursions is significant and should be encouraged. CleanCo expects that a separate inertia market will be required eventually, but this should be considered through the ESB's post 2025 review. In the interim, implementing Infigen's FFR proposal (adjusted to include inertial response) is an appropriate step.
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?	Yes
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	Nil
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	The temporal disconnect and the one-sided nature of the existing causer pays model significantly reduces efficiency in the market. These limitations reduce the link between a business's performance and its reward/cost and lead to higher overall costs for regulation FCAS. This should be rectified through this review.
4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	This is a good opportunity to adjust the Frequency Operating Standard to reflect the AEMC's expectations of frequency performance within the normal operating band. The AEMC's decision on MPFR reflects a view that there is an optimal (or at least sub-optimal) distribution of frequency within the normal operating band – the AEMC should be explicit about, and consult on, those views.
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?	Nil
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	Nil
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?	As mentioned above, having some level of FFR (including inertial response) is reasonable and simple first step. Maximising the system response in the shortest time possible is likely to reduce the magnitude and length of frequency disturbances.
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	Nil

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?	Nil
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?	Nil
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?	Nil
2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?	Nil
3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	The most important step is to improve the forecasts in pre-dispatch and ST-PASA. An improvement in forecasts is required regardless of the final market structure as better clarity on the demand/supply balance and network conditions enables participants to better make informed and timely commitment decisions. Moreover, without improving pre-dispatch the implementation of any aheadness will not provide meaningful certainty.
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?	CleanCo prefers a causer-pays approach where there is a clear link between a business's/customer's action and the cost. To the extent there is no clear causer, the ownership of the liability must be clear and forecastable. This will help stimulate secondary markets and underwrite investment.
2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	Nil
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	Nil
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper?	CleanCo sees the Infigen FFR (adjusted for inertial response) and Hydro Tasmania rule changes as no-regrets and supports fast-tracked implementation. Similarly, there is very little overlap between the TransGrid proposal and other issues covered in this process, so it can be considered independently on its own merits. The Delta and Infigen Operating Reserve papers will require further consideration and integration into the ESB Post 2025 process.