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Dear Commissioners,

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CAPACITY COMMITMENT MECHANISM AND SYNCHRONOUS SERVICES MARKETS DIRECTIONS PAPER (ERC0306 & ERC0290)

EnergyAustralia (EA) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC's) Directions Paper on a Capacity Commitment Mechanism and Synchronous Services Market for the National Electricity Market (NEM). EA is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. EA owns, contracts and operates a diversified energy generation portfolio that includes coal, gas, battery storage, demand response, solar and wind assets. Combined, these assets comprise 4,500MW of generation capacity.

EA is dedicated to building an energy system that lowers emissions and delivers secure, reliable and affordable energy to all households and businesses. This requires being a good neighbour in the communities we operate in. We, therefore, recognise Aboriginal and Torres Strait Islander peoples as the traditional custodians of this country and acknowledge their continued connection to culture, land, waters and community.

EA is appreciative of the AEMC's efforts to investigate the future procurement, scheduling and dispatch arrangements for Essential System Services (ESS). Ensuring these settings are fit for purpose will be a vital enabler of a rapid and robust energy market transition. The key points in this submission are:

- We strongly support the Energy Security Board's (ESB's) long-term vision to move to an unbundled, services-based approach to ESS procurement.
- Defining ESS in terms of fundamental power systems attributes and the quantity required will be critical to achieving this vision and should be expedited immediately.
- No proposed solution will address the efficiency and investment issues of the current asset-based approach to ESS procurement. Identifying the best interim solution will, therefore, require a more detailed assessment.
- The status quo might be maintained if:
    - the expected inefficiency of future interventions is low,
    - the time until ESS are defined appropriately for services-based procurement is short,
    - alternative solutions prove too costly or too risky to implement, or if

    - other possible changes to current arrangements prove valuable.

- Owing to likely costs and complexity, we suggest the Binary Market Ancillary Services (MAS) solution is investigated further only if other proposed approaches prove intractable.
- A linear MAS approach may prove the most dynamically efficient of all options, however, quantification of the likelihood of perverse, partial dispatch outcomes and the associated security and efficiency impacts is required.
- We disagree that a linear MAS would necessarily be more expensive, less secure and could not handle inter-temporal considerations per a non-MAS (NMAS) approach.
- It is not clear that using an Australian Energy Market Operator (AEMO) controlled NMAS approach for scheduling system strength contracts is possible, required or desired.
- We hold great concerns that the NMAS objective function may result in a move to centralised market operation. This must be avoided given the theoretical and practical deficiencies of centralised markets and their incompatibility with the current NEM design.
- The optimal interim solution must be simple, low cost and minimise interruptions to the NEM. This will promote the fastest and easiest transition to a services-based ESS procurement approach.
- We encourage the AEMC to take the necessary time to further investigate each option to achieve these outcomes so that more practical and forward-thinking rulemaking can occur in line with the AEMC's strategic plan.

EA is ready and able to assist the AEMC in this endeavour. Further detail on specific issues can be found below and we would welcome the opportunity to discuss this submission further with you. Should you have any questions, please contact me via bradley.woods@energyaustralia.com.au or on 0435 435 533.

Regards,

Bradley Woods
Regulatory Affairs Lead

The Long-Term Power System Vision Requires Immediate Action

The ESB's long-term vision for the power system is that it is efficient, secure and reliable. This includes explicitly unbundling ESS so that they can be individually valued, priced and procured. EA strongly supports this services-based approach and appreciates the AEMC's efforts in realising it through this and other rule changes.

Unfortunately, the industry is a long way from achieving this vision. The work to translate fundamental power system requirements into individual ESS has yet to occur. This means transparent price signals for ESS investment are 'missing'. The longer these remain so, the longer AEMO will have to intervene to ensure sufficient ESS are available via the dispatch of critical generation configurations.

This asset-based approach will become increasingly inefficient and unsafe as the grid of the future moves farther from that of the past. That is, as the number of synchronous generators that typically provide the bulk of ESS diminishes, and the economic conditions necessary for their continued operation deteriorates.

To its credit, AEMO is investigating how these risks can be best met through the Engineering Framework. EA is highly supportive of this initiative. However, it is currently unclear if, or when, defining ESS in terms of their fundamental power systems attributes and the quantity required will be explicitly included.

Unfortunately, defining ESS in this manner cannot wait. Beyond mitigating the risks and costs of the current asset-based approach, a services-based approach will help to ensure:

- the efficient and timely exit of thermal generators,
- promote the efficient and timely entry of new technologies to replace them,
- increase the diversity of supply, ESS competition and keep service costs down, thereby,
- resulting in a cheaper, more flexible and increasingly resilient power system.

We strongly encourage the AEMC to set a firm date for AEMO to complete this critical engineering work. Once complete, we suggest the Reliability Panel be engaged to consider and mandate the ESS procurement framework settings to appropriately balance any economic and engineering trade-offs. Doing so will allow for the fastest possible transition from an asset-based ESS procurement approach to an unbundled, services-based one. This will ensure timely and efficient ESS investment, increased operational security and, ultimately, lower costs to customers.

All Interim Solutions Are Imperfect

Until the foregoing is achieved, there is little credible alternative to the current asset-based ESS procurement approach. The AEMC is, therefore, right to ask whether this approach can and should be optimised in the interim. Answering this definitively will, however, require further analysis and deliberation. This is because all interim options suffer similar deficiencies around efficiency and investability.

On efficiency, all options would continue to contravene the economic principle of fidelity. That is, with one price[1] continuing to signal the value of multiple ESS. Until the required

[1] Under the status quo, this would be the direction cost. Under the MAS and NMAS alternatives, this would be the generator commitment bids.

levels of individual ESS for a given operating condition are defined, inefficient procurement of one or more ESS is virtually guaranteed. This is due to operators having limited ability to consider how *individual* ESS can be traded off such that a more efficient, but still safe, dispatch outcome occurs. Ultimately, this simply results in excess costs to customers.

Achieving the system services objective requires efficient longer-term investment in ESS supply. However, forecasting ESS investment opportunities is a notoriously capricious exercise. Business cases based solely on ESS revenues, therefore, face excessive hurdle rates for approval. This risk can be defrayed with investment incentives, cost-sharing arrangements or long-term contracting. Unfortunately, none of the proposed options contemplates such mechanisms. That is, although each option may provide additional revenue *opportunities*, none provides the requisite revenue *certainty* for investment.

Without these or other elements to reduce investment risk and increase revenue certainty, it is unlikely that any proposed option will optimally achieve the system services objective. It is, therefore, critical that the preferred interim solution is simple, low cost and minimises interruption to the NEM. When coupled with a sunset date, this will promote the fastest and easiest transition to services-based ESS procurement.

Maintaining The Status Quo Requires Further Quantification

The Directions Paper highlights that the number of AEMO interventions and their duration has increased in recent times. This has proved extremely costly for customers. Directions for system strength in South Australia were more than $22m for the first quarter of 2021 alone. Moreover, total system security costs were over $150m in the second quarter of 2021[2].

EA agrees that directions should be used only as a last resort. Further, that the current directions framework is imperfect and can lead to inconsistent, inefficient and opaque interventions. This is because:

- there is no single tool that AEMO operators can use to assess all system requirements and compare the relative benefits of different operational decisions at once,
- information is manually collected and analysed,
- the market does not know what the intervention will be, nor its impact, and
- intervention is based on a least-cost assessment with compensation set at the 90th percentile.

Despite this, we do not consider that full responsibility for the statistics above lies with the interventions framework. High total system costs have largely been due to rare, one-off power system shocks. For example, Q1 2020 costs were driven by the collapse of several transmission towers in Western Victoria. Meanwhile, high Q2 2021 costs were the result of an explosion at the Callide power station.

On system strength, it is well known that issues in South Australia are the dominant factor. For example, South Australian directions accounted for more than 98% of all power system directions in 2019-20[3]. However, this situation is not expected to persist given the commissioning of four new synchronous condensers. EA understands that even

[2] AEMO Quarterly Energy Dynamics Report Q2 2021.
[3] Per the Directions Paper, AEMO issued 278 directions. Only 5 were not in South Australia.

with only two of the four being operational since August, there has been a marked reduction in time under direction in South Australia.

Determining the level of inefficiency of future interventions will be a critical task in determining whether change is required. As will the time until ESS are defined in terms of fundamental power system attributes. Should this prove to be shorter, with inefficiency concerns proving immaterial, then the case for change will be weak. That is, with the costs associated with maintaining the admittedly imperfect current arrangements likely to be far lower than the net benefits from designing and implementing an alternative solution.

This may be a difficult task. AEMO should be able to provide very good estimates of the costs and likelihood of the recurrence of previously identified power system issues. However, forecasting new system security issues is notoriously complex and hostage to many assumptions. This makes determining the efficient system-wide level of interventions imprecise.

Despite this, EA strongly encourages the AEMC to expedite this work. Having even rudimentary 'size of the prize' analysis will allow for sensitivities to be developed to better inform rulemaking. For example, from being able to translate the costs of developing alternative solutions into an equivalent directions 'budget' with which to compare inefficiencies of the current framework.

To be clear, this approach is not EA's philosophical preference. We strongly believe the use of directions should be minimised as much as possible. This is due to the potential for distortionary market impacts and investment disincentives. To the extent maintenance of the status quo proves to be the simplest and cheapest option, however, we would support it as a pragmatic interim move toward a fully unbundled, services-based solution. Even so, we urge further thought be given to how the current interventions framework could be made more efficient. For example, by:

- increasing the transparency on the type of interventions and their expected impacts so that a more effective and efficient market response can result,
- investigating how current Network Support and Control Ancillary Services (NSCAS) arrangements might be better used to ensure longer-term ESS provision, or
- considering whether tender processes for 'must-run' generation, along the lines of the current System Restart Ancillary Services (SRAS), may help keep costs down.

A Binary MAS Is Unlikely To Be The Best Approach

The MAS approach would see the NEM Dispatch Engine (NEMDE) and the Pre-Dispatch (PD) engine updated to better reflect the physical requirements of the system. This would be coupled with new bidding architecture for ESS supply. Combined, this would promote a co-optimised energy, Frequency Control Ancillary Services (FCAS) and ESS dispatch outcome that is more likely to meet system security constraints.

The MAS approach has several advantages. It would allow for the most dynamic valuation of ESS and allow co-optimisation of almost all energy services. Together, this is likely to lead to the most efficient outcomes of all the proposals. Albeit, that these will still be sub-optimal when compared to a fully unbundled services-based approach as explained above.

The Binary MAS option would use binary constraints to represent unit commitment status to ensure secure dispatch outcomes. This would likely provide more precision than a Linear MAS approach. Indeed, we have used integer unit commitment variables in PLEXOS to provide more sophisticated modelling insights.

However, as noted in the Directions Paper, binary optimisations are costly, complex and ramify quickly as the number of variables increases. Moreover, it is not clear that such precision is desirable or would even result. For example, the Electric Reliability Council Of Texas (ERCOT) requires thousands of servers to run its system. Even then, computations do not always resolve in the necessary runtimes[4].

There are many differences between ERCOT and the NEM. However, with the NEM now settled on a 5 Minute basis, and with smaller, variable generators becoming an increasingly larger proportion of the total generation fleet, we question whether a Binary MAS would guarantee secure dispatch outcomes in the required timeframes. Even if so, we do not see that it would be the most economical solution. We, therefore, suggest that a Binary MAS be considered further only if other approaches prove intractable.

A Linear MAS Approach May Be Better Than An NMAS One

Excluding a Binary option would mean the MAS Approach would have to be based on a linear optimisation method. This would necessitate the use of linear approximations of non-linear phenomena such as unit commitment. Depending on how these are formalised, this could see situations where the most efficient outcome is non-sensical. For example, to turn on only part of a generator. In turn, this could lead to insecure or inefficient dispatch schedules.

The AEMC cites these security and efficiency concerns as one of the key reasons for preferring an NMAS approach. However, we do not consider this preference can be so definitive at this juncture. Despite statements to the contrary in the Directions Paper, the NMAS approach cannot guarantee secure dispatch outcomes. This is due to the timing differences in the gate closure and run time necessitated with an optimiser outside the current market. Simply put, any system security condition that changes within this time will not be able to be reflected and optimised as part of the solve routine. This means NMAS dispatch will still have the potential for insecure outcomes.

The same arguments apply to efficiency concerns. The inherent inflexibility in the NMAS approach may see inefficient dispatch outcomes locked in for longer than under a more flexible NMAS approach. The AEMC contends this would be more than offset by the lack of inter-temporal optimisation in the MAS approach. However, this overlooks the fact that participants already take, and optimise for, inter-temporal concerns as part of their current bidding decisions. For example, choosing to remain on during the middle of the day at minimum generation to avoid start-up costs and delays to capture expected higher prices later on. These inter-temporal considerations would be unchanged under the MAS approach.

The risks and implementation costs of the MAS approach are other reasons cited for preferring the NMAS approach. Here we agree with the AEMC that, prima facie, the likely risks of overhauling NEMDE and the PD engine would be greater than developing an independent outside optimiser, depending on how the MAS is designed. However, these risks need to be weighed against the costs and benefits of each approach.

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[4] Per Cramton (2017).

The MAS approach is posited to be more expensive than an NMAS one. This is on the basis that it would be simpler to build an NMAS optimiser than alter NEMDE. Further, that a NMAS approach would obviate participant system change costs. However, this may not be so. The Hydro Tasmania proposal would see only incremental changes to NEMDE with little to no participant costs incurred. Thus, making it likely to be far cheaper than an NMAS alternative.

It is a similar story on the benefits side. Valid comparison with the other approaches can only occur once the possible security and inefficiency implications of the MAS approach are better known. It could be that the perverse, partial outcomes resulting in insecure dispatch are infrequent. Or that rules to 'round up' to account for partial solutions, while not optimally efficient, are immaterial. If so, it would seem that a MAS approach would be preferable to an NMAS one.

One clear advantage of the MAS approach is the ability to co-optimise ESS dispatch with that of energy and FCAS. This is something the NMAS approach cannot do which we consider will become increasingly important over time. That is, given the interrelationship between negative energy prices and unit commitment decisions. A solution that better accounts for and co-optimises these variables is, therefore, more likely to result in both a more efficient and secure dispatch outcome.

Despite this, we note that even if the MAS proved a better solution than the NMAS approach, it may still not be justifiable when considered against the status quo. For example, if MAS development costs resulted in a directions budget that covered the expected future system interventions costs until an unbundled, services based-approach began. Alternatively, it could be that the risks of updating NEMDE are considered too high. As above, we strongly encourage the AEMC to undertake further analysis to quantify the merits of the MAS approach to better inform decision making.

The NMAS Approach Has Several Question Marks

The NMAS approach would use an optimiser outside NEMDE to procure and schedule ESS. This would allow a wider range of ESS contracts and variables to be evaluated and optimised for dispatch compared with the MAS approach. For example, existing NSCAS contracts, Transmission Network Service Provider (TNSP) contracts for system strength and other short-term security contracts entered into by AEMO could all be included. Moreover, it would explicitly allow for the optimisation of unit commitment over multiple periods.

The AEMC contends that these design features would allow for greater efficiency and security than the MAS approach. As demonstrated above, however, the NMAS approach cannot guarantee secure dispatch outcomes or optimal efficiency given the inflexibility locked in by gate closure and run-time constraints. Moreover, it is not true that the MAS approach could not also include inter-temporal optimisation elements. It, therefore, remains an open question whether the MAS or NMAS approach would result in more efficient and secure dispatch.

The NMAS approach has other question marks. It is not clear that AEMO could schedule system strength contracts without being a legal party to the agreements between TNSPs and generators. It is highly unlikely this additional complexity would be welcome or add to efficient negotiations.

It is also unclear whether an AEMO optimiser is required to ensure secure and efficient system strength outcomes. The Tasmanian system strength arrangement between Hydro

Tasmania and TasNetworks is an excellent exemplar. Based on forecasts of unit commitment, operators at TasNetworks can call on additional synchronous machines to be activated to ensure compliance with minimum fault level obligations. Although AEMO is *informed* of contract activation, it is not *involved* in contract activation. As we understand it, this arrangement has not increased system security incidents nor onerous cost increases to customers. There would, thus, seem little reason why such an approach could not be applied in Mainland states.

The NMAS Objective Function Is A Great Concern

The AEMC has stated that the NMAS optimiser's objective function would be based on net market benefits. That is, in recognition of the trade-off between the costs of procuring ESS beyond minimum levels to promote the dispatch of additional, lower-cost generation.

In principle, this makes economic sense and would likely be an improvement over NEMDE's least-cost dispatch algorithm. That is, with least-cost outcomes not necessarily equating to maximum net market benefits in all situations. However, it is unclear whether the AEMC intends this will apply even if no system security issues arise in normal dispatch. If so, this would represent a fundamental departure from current market functioning and AEMO's current remit. That is, with AEMO limited to interventions or activation of additional system security contracts only when the power system is not, or is not expected to be, in a satisfactory operating state[5].

Applying the net benefits approach only when a system constraint is projected to bind in normal dispatch might seem to negate this issue. However, even here the picture quickly becomes murky. Should AEMO be allowed to activate additional contracts so that the constraint is only just alleviated, or should it be able to activate as much generation as possible such that it maximises net benefits? What about when there are net benefits to dispatching additional generation, but it won't *entirely* relieve a security constraint?

Once again, although each case may result in lower-cost energy market outcomes, this would not be in keeping with the purpose of security contracts nor the intent of the Rules. Unfortunately, it is difficult to see how a solver with only a net benefits objective function could fully distinguish these cases. It would, therefore, be vital to have clear guidelines and restrictions on AEMO's use of the NMAS mechanism so that participants maintain sovereignty to bid their plant as they see fit. Without this, the market would be moved alarmingly closer to a centralised one.

Some might argue this would be an improvement on the current NEM design. Indeed, some research has concluded centralised energy markets may be slightly more efficient than decentralised markets. Shioshansi, Oren and O'Neill (2008) simulated the New England energy market and concluded welfare losses were 4.25% lower under a centralised approach. Camelo, Papavasiliou, de Castro, Riascos and Oren (2018) found reductions in welfare losses of 3.32% from a centralised market compared to a decentralised one in a Columbian market simulation. However, these studies were hostage to several methodological issues, namely:

- Sioshansi, et al. assumed producers bid truthfully at all times in centralised markets. This is an assumption proven false by many, including the same authors

[5] Per Chapter 4 of the National Electricity Rules.

in later work. See Sioshansi and Nicholson's (2011) and Ahlqvist, Holmberg and Tangeras (2019) for further detail.

- Both the New England and Columbian studies used heuristic-based approaches to calculating welfare efficiency. This is due to the difficulty of using game-theoretic (Nash Equilibria) approaches for large, centralised markets with non-convexities (e.g., start-up costs). However, in doing so, both neglected the repeated intra and inter-day trading possible in decentralised markets that result in increased efficiency.

Similarly muted benefits and confounding variables are seen in the limited number of empirical studies of centralised markets. Zhang (2016) found that the change from a decentralised to a centralised market by ERCOT in 2010 lowered production costs by only .5%. Evaluating the same change, Zarnikau, Woo and Baldick (2014) found spot prices were reduced by only 2% on average.

Although these might seem like worthwhile improvements, it is impossible to attribute how much of this was the direct result of centralisation. As noted in Zarnikau et al., and highlighted by Ahlqvist et al., ERCOT also changed from zonal to nodal pricing and moved from 15 to 5-minute delivery periods as part of the market reforms. It is, therefore, likely that centralisation had no, or only limited, benefits.

Such an outcome would be in keeping with findings from Riascos, Bernal, de Castro and Oren (2016). In an econometric study of a change to centralised unit commitment in Columbia, production efficiency improvements were noted. However, these gains were captured by producers via more strategic bidding that resulted in higher electricity prices. There were, thus, no benefits to consumers.

These results should come as no surprise. The theoretical and practical deficiencies of centralised markets are well known. These include:

- Bidding formats that do not allow producers to express all details in their costs. This is particularly problematic for combined cycle gas turbine and run of river hydro-electric assets which typically have saw-toothed marginal costs.
- The requirement for nodal pricing and related information on network congestion to ensure efficient dispatch, which can also result in hedging illiquidity and increased exercise of market power[6].
- The incentive for producers to exaggerate costs due to uplift payments.
- The unbalanced nature of uplift payments requires trade-offs between rents and efficiency when designing tariffs to fund uplift payments.
- Intensive computer resources to clear large markets.
- Lack of transparency about clearing outcomes makes it hard for participants to understand why a bid was accepted or rejected, therefore, impacting subsequent bidding efficiency.
- Gate closures and run-time requirements make it hard to incorporate changes in forecast and actual renewables output leading to inefficient market dispatch.

Recognition of these deficiencies has seen the United Kingdom and Ireland abandon centralised markets altogether. Meanwhile, other regional transmission organisations including PJM and NYISO have introduced balancing mechanisms and intra-day markets

[6] A participant who has hedged a large fraction of their output will have less incentive and ability to influence short term prices.

to improve flexibility and efficiency. That is, they have sought to move closer to, rather than further from, decentralised markets to correct for centralised market inadequacies.

Decentralised markets are not perfect. Disorderly bidding, collusive outcomes and inefficiencies from non-convexities are potential risks if not designed well. Indeed, the AEMC's recent changes to introduce 5-Minute and Global Settlement referenced some of these concerns. However, with these rule changes now made and noting the issues above along with the costs of any transition, it is hard to see how anything that pushes the NEM closer to a centralised arrangement could be justified. Even if only applied to ESS. It is, therefore, critical that the NMAS objective function be evaluated in light of these concerns so that the efficient, existing energy and FCAS outcomes are appropriately protected from any ESS changes.

Designing an NMAS objective function that avoids centralisation impacts would overcome a significant concern. However, this would still leave the other noted issues above requiring resolution. Once again, we encourage the AEMC to undertake further work to quantify and better examine these so that fair and rigorous comparison with other options occurs. It is only through such work that more practical and forward-thinking rulemaking can occur in line with the AEMC's strategic plan.

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