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Ms Anna Collyer
Ms Merryn York
Mr Charles Popple
Ms Michelle Shepherd
Ms Allison Warburton
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Lodged electronically: http://www.aemc.gov.au

Dear Commissioners,

NATIONAL ELECTRICITY AMENDMENT (INTEGRATING ENERGY STORAGE SYSTEMS INTO THE NEM) RULE 2021 (ERC0280)

EnergyAustralia (EA) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC's) options paper on Integrating Energy Storage Systems into the National Electricity Market (NEM).

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

EA is dedicated to building an energy system that lowers emissions and delivers secure, reliable and affordable energy to all households and businesses. EA is, therefore, appreciative of the AEMC's efforts to investigate whether current regulatory settings for energy storage systems, including more complex hybrid facilities, are appropriate in light of ongoing and significant market, technological and operational change. Ensuring these settings are fit for purpose will be a vital enabler of a rapid and robust energy market transition.

The critical points in this submission are:

- EA supports storage reform Option 3 as it strikes an optimal balance between addressing exigent, short-term storage issues while minimising the costs and risks associated with incompatible storage frameworks over the longer term.
- It is critical that Option 3 equalises treatment of Use Of System (UOS) charges between utility-scale Distribution Connected Storage (DCS) and Transmission Connected Storage (TCS).
- EA considers Option 3 could be made even more appealing by including flexible transitional arrangements, such as allowing participants to choose whether to move to the new framework or not. This will ensure that existing participants are not disadvantaged by regulatory framework changes.

- Although appreciating the flexibility benefits from having a dynamic scheduling obligation, it is not clear what impacts this might have on market forecasting, dispatch and scheduling outcomes. EA, therefore, suggests further investigation be undertaken to understand these issues better.
- EA supports the retention of the current arrangements for performance and access standards. That is, with the onus on developers to meet system standards by factoring performance issues into site designs. That is, rather than system standards being weakened to support specific or unusual reticulation configurations.
- Option 3 would apply the causer pays approach to all market participants based on separately measured consumed and sent out energy at each connection point. However, EA notes that the same outcome could be achieved using net flows at each connection point. This is likely to be simpler to implement and in keeping with existing arrangements for pumped hydro.
- EA considers there may be merit in investigating whether the shared asset guidelines might be tightened to reduce the cost impacts from establishing and applying standards for network owned and operated storage if the cost impacts are material.
- EA supports further investigation of DC-coupled storage, noting these are likely to become more prevalent for the commercial and technical reasons outline below. EA also supports a review of ancillary service provisions only once outcomes of the Energy Security Board's (ESB's) Two-sided Market (2SM) workstream are known with sufficient clarity.

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

Regards,

Bradley Woods
Regulatory Affairs Lead

Question 1: Is introducing a new participant category, an Integrated Resource Provider (option 4), to better facilitate entry and participation of storage and hybrid facility, more preferable than modifying existing participant categories (option 3)? Are either option 3 or 4 more preferable to options 1 and 2?

In response to the earlier consultation paper, EA proposed an incremental, 'do-now' approach to resolving storage integration issues. We note that Option 3 (modifications to existing participant categories) is consistent with that proposal and would:

- simplify and reduce the registration process, requirements and costs;
- clarify and accommodate arrangements for bi-directional flows;
- maintain existing dispatch flexibility in terms of the number of price bands;
- respect the technology-neutrality consultation principle;
- avoid the costs and risks of substantial regulatory reforms to support new definitions and participant registration categories; and
- support the transition to a future, universal participant category model without predetermining outcomes of the ESB's 2SM work, as option 4 risks.

In short, Option 3 strikes an optimal balance between addressing exigent, short-term issues while minimising the costs and risks associated with inconsistencies between storage framework reforms over the longer term.

EA contends this option could be made even more appealing by including flexible transitional arrangements. For example, by not mandating that existing storage and hybrid participants have to move to new rules settings. Leaving businesses free to choose which settings are most suited to their operational and strategic goals will minimise change costs and maximise market efficiency.

Question 2: Do you agree that, if an Integrated Resource Provider category (option 4) is established, battery aggregators should use that category and MSGAs should not be allowed to classify storage units exempt from the requirements to register as a Generator? And in that case, should the current arrangements regarding the provision of market ancillary services by MSGAs be maintained?

Option 4 possesses some of the same benefits as Option 3, such as a single registration process and participant category. However, EA does not consider that Option 4 should be pursued at this time. Option 4 proposes a new registration category that would require significant changes to apply obligations to services, rather than assets per the current arrangements. Although this would seem to move closer to the framework envisioned under 2SM, this work is very immature and not expected to be completed for some time. Prematurely implementing Option 4 without this work being sufficiently developed runs the risk of incompatible framework outcomes, which would require further future consultation to correct. In contrast, Option 3 would improve current storage arrangements and support a future transition to 2SM category models without introducing such risks.

Question 3: Should existing storage participants be transitioned to a single participant category (as they are currently registered as both a Market Generator and Market Customer)?

EA prefers Option 3, which would not require any transition to a single participant category or place a retrospective burden on existing participants with storage assets including pumped hydro.

Question 4: What proportion of a hybrid facility's sent-out generation capacity would need to be dispatchable for the whole of the hybrid facility's sent-out generation to be able to follow dispatch instructions, under a single DUID? Would a dynamic approach to scheduling obligations, for example shifting between scheduled and semi-scheduled obligations based on the state of charge of the storage unit, be appropriate, and how should this operate? Could the same approach be taken to scheduling load where storage is added to a Market Customer's site, or should different considerations apply?

Although appreciating the flexibility benefits that would accrue from having a dynamic scheduling obligation, it is not clear what impacts this might have on market forecasting, dispatch and scheduling outcomes. It would be unfortunate if additional flexibility undermined existing market processes or results in perverse effects due to obligation gaming. EA, therefore, suggests more investigation be undertaken to understand better these issues, including leveraging the Australian Energy Market Operator's (AEMO's) insights on the possible implications for the NEM Dispatch Engine (NEMDE).

Question 5: Do you agree that 20 price bands would be appropriate for grid-scale batteries or would another number of bands be more appropriate?

EA agrees that maintaining competitive neutrality between market participants is desirable and supports 20 price bands for grid-scale batteries.

Question 6: Are there certain configurations of hybrid facilities that cannot, or should not, be dispatched at a single connection point? What benefits are achieved by dispatching a hybrid facility at a single connection point, and what issues arise?

From a NEM operational perspective, dispatching a hybrid facility from a single connection point under two DUIDs is most efficient given its consistency with current dispatch and settlement arrangements. However, as noted in the consultation paper, this may not result in equal obligation treatment for technologies within a hybrid facility compared to those that stand alone outside of it. As with the answer to Question 4 above, further investigation is required to quantify the technical and economic implications of trying to remedy this inequity. If wholesale changes to NEMDE or other market systems and processes are required, it may be that some hybrid configurations should be disallowed in order to keep costs for customers down.

Question 7: What issues may arise if performance and access standards are set at the connection point for hybrid facilities? Would these standards need to be amended to provide appropriate flexibility for hybrid facilities?

EA is highly cognizant of the issues pertaining to the translation of performance metrics between generation terminals and the shared network connection point. For example, windfarm reticulation configuration can mean system strength varies significantly at each turbine compared with that seen at the connection point. This will be magnified should a mix of different technologies exist in a hybrid facility. For example, where there is synchronous, asynchronous, grid-forming or grid-following componentry.

However, in supporting Option 3, EA supports the retention of the current arrangements for performance and access standards. That is, with the onus on developers to meet system standards by factoring performance issues into site designs. This is rather than system standards being weakened to support unusual reticulation configurations. Continuing the approach of setting performance standards at the connection point for hybrid facilities will also ensure that the obligation to remedy non-compliance is clearly with the participant, who is in the best position to understand the root cause(s) of non-compliance within its facility.

Question 8: Which option do you consider to be the most appropriate for the recovery of non-energy costs from market participants? Are there any other factors the Commission should consider when deciding how non-energy costs should be recovered from market participants? Are there any implementation issues the Commission should consider?

Option 3 would apply the causer pays approach to all market participants, irrespective of the participant category in which they are registered. This would see cost recovery based on separately measured consumed and sent out energy at each connection point. However, EA notes that the same outcome could be achieved using net flows at each connection point. This would seem a simpler alternative given:

- AEMO already receives net meter data for each Financial Responsible Market Participant (FRMP) for each trading interval, and
- it would be in keeping with existing arrangements for pumped hydro where pumping load is treated as auxiliary supply and, effectively, netted for the purposes of calculating participant fees and charges.

Regardless of which variant of Option 3 is chosen, in equalising the treatment of different technology types, more efficient investment outcomes will be promoted. EA, therefore, supports Option 3 for the purposes of non-energy cost recovery.

In terms of other storage costs, EA considers there is a pressing need to equalise Use Of System (UOS) charges between utility-scale Distribution Connected Storage (DCS) and Transmission Connected Storage (TCS). That is, for Distribution UOS charges not to apply for consumed or imported energy ala existing Transmission UOS arrangements. As highlighted in our submission to the earlier consultation paper, DCS combines the scale efficiency and control benefits provided by transmission connected storage with the locational advantages seen with customer connected storage. Unfortunately, the uneven charging treatment of DCS, when compared to TCS, is undermining the business case for DCS investment. In turn, this is resulting in sub-optimal NEM investment outcomes and undermining achievement of the National Electricity Objective (NEO).

Question 9: Do you support the solution outlined in this options paper for resolving the potential issues with establishing standards for NSP owned energy storage? If not, do you consider there to be other potential solutions for resolving this issue?

EA notes the arguments that have been raised against Network Service Providers (NSPs) being treated differently for the purposes of connecting their own storage. Primarily, that no independent assessment is required when connecting other network equipment such as transformers or synchronous condensers, so why should storage be any different? However, these arguments overlook the fact that there are no competitive markets for such assets, which is not the case for storage. The risk is that in allowing NSPs the flexibility to manage their own connections, perceptions of a non-level playing field in storage connection and supply may develop. For example, in processes or preferential treatment that may impact both costs and timing of storage connection, which could then undermine investor confidence and investment outcomes.

In this sense, EA considers there may be value in employing AEMO or another independent party, such as an engineering advisory consultancy, to negotiate and validate connection agreements. This is to help promote and maintain the transparency and competitive neutrality of NSP owned energy storage projects. However, EA is conscious of the costs that customers may be burdened with as a result. For example, from increases in either network or AEMO charges to cover the requisite administration. If these turn out to be substantial, it may be worth investigating whether the shared asset guidelines might be tightened to reduce this impact. For example, increasing the percentage reduction that applies to unregulated revenues earned from NSP-owned storage shared assets.

Question 10: What capital, operational or efficiency benefits do DC-coupled systems provide participants and the NEM as a whole, and how might these benefits help consumers in line with the NEO? Do you support amending the NER to permit the registration and operation of DC-coupled systems? If so, how should they register and operate?

When designed at the onset with hybrid facilities in mind, DC-coupled systems provide numerous opportunities to save costs. This can occur both in the construction stage and ongoing life-cycle operations and maintenance timeframe from avoiding duplication of system components compared with two inverter system designs. For example, in terms of spares holdings, cooling apparatus and monitoring and control systems. These costs savings directly lead to efficiencies in line with the NEO.

However, as with the answer to Question 4 above, EA considers further investigation is required on this issue. In particular, to know if dynamic, trigger-based obligations can be technically and economically accommodated within NEMDE. Even if this turns out to be viable, EA notes that further assessment will be required to ensure no deleterious consequences for other market forecasting and dispatch processes result.

Question 11: Do you support AEMO's proposal to redraft the ancillary services provisions in Chapter 2 of the NER to make them more consistent with the services approach to regulation currently being considered by the ESB's two-sided market work?

Consistent with the answer to Question 2 above, EA sees risks with advancing rule changes ahead of the completion of the 2SM review. That is, in setting up incompatible definitions, frameworks and outcomes which would require more consultation to correct in future. EA, therefore, suggests this proposal be revisited only once the effects of the 2SM review are known with sufficient clarity.