EnergyAustralia
LIGHT THE WAY

16 September 2021

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Dear Commissioners,

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

EnergyAustralia (EA) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC's) Draft Determination on Integrating Energy Storage Systems into 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, which requires being a good neighbour in the communities we operate in. As part of this, we recognise Aboriginal and Torres Strait Islander peoples as the traditional custodians of this country and acknowledge their continued connection to land, waters, culture and community.

EA appreciates the AEMC's efforts to investigate whether current regulatory settings for storage and hybrid systems 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 key points in this submission are:

- EA is strongly supportive of the intent behind the Integrated Resource Provider (IRP) participation, registration and categorisation framework. However, given the previous Option 3 has largely the same benefits and, prima facie, would be much cheaper, we query whether the IRP approach is to be preferred. If the AEMC has further information that indicates the IRP option is superior, we strongly support this being communicated.
- EA acknowledges the AEMC's concern that exempting storage from use of system charges could advantage it compared to other loads or generators. However, we do not consider it applicable to storage assets whose main purpose is providing generation or grid services. Where energy is *temporarily accumulated or used for later public generation or security service provision*, rather than being *ultimately consumed for private end-use,* storage assets should be treated consistently with

other generators, not loads. That is, in line with other international jurisdictional rulings.

- Retaining existing charging arrangements are unlikely to enhance Australia's attractiveness as a destination for the deployment of global storage investment capital. Nor will they lead to optimally efficient local investment outcomes. For example, from perpetuating current distortions from the double-charging of use of system costs, unequal treatment compared to other generation sources and the potential for inefficient locational incentives. We, therefore, strongly encourage the AEMC to consider the long-term consequences of not changing charging settings at this time.
- Amending the non-energy cost recovery framework so that it occurs on a gross basis is supported. As is the general approach for DC-Coupled Systems and the decisions not to change the performance standards measurement location, Marginal Loss Factor calculation methodologies and Reliability Panel representation.
- EA strongly agrees that no asset, whether Network Service Provider (NSP) owned or otherwise, should be given preferential treatment in the connection process. Although acknowledging the ring-fencing guidelines review is ongoing, we consider there may still be a need for other Rules-based protections to ensure that consistent, transparent pricing and connection outcomes are seen NEM-wide. We, therefore, encourage the AEMC to commit to re-examining this issue post conclusion of the ring-fencing review.

More detailed responses on the Draft Determination issues are provided below. 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

Participation Framework

The Draft Determination recommends that a refined Option 4 from the earlier Options Paper be adopted. This would see the new Integrated Resource Provider (IRP) category introduced to streamline the registration and participation frameworks for storage and hybrid assets. EA is strongly supportive of the intent behind this proposal which would also see one registration fee payable, one Dispatchable Unit Identifier employed and retention of existing bidding, technical standards and connection point arrangements. However, EA does not consider the IRP approach can be fully endorsed at this time without further information on the cost and benefits relative to other alternatives. In particular, Option 3 from the earlier Options Paper, the discussion of which is almost entirely absent from the Draft Determination.

As described by the AEMC, both Options 3 and 4 would:

- result in a cheaper, simpler and more efficient registration and categorisation process than current arrangements;
- support new services provision by smaller providers;
- maintain existing dispatch flexibility in supporting 20 price bid bands;
- retain current connection point and performance standard settings; and
- respect the technology-neutral consultation principle.

The key differences between the two options lie in the registration approach and alignment with the Energy Security Board's (ESB's) mooted trader-services model. The IRP approach would see a new participant category introduced while Option 3 would change existing participant categories to effect the same outcomes. The IRP approach would take a larger step toward the trader-services model and likely obviate further ESB reforms relating to virtual power plants and 'behind the meter' engagement. Option 3 would take more of an incremental step toward the trader-services model. However, as noted in the Options Paper, in representing an advancement over current settings, Option 3 could also support any future, universal participant category envisioned by the ESB.

The Australian Energy Market Operator (AEMO) has estimated the up-front costs for implementing the IRP option will be between $19m and $28.7m. However, if the recent 5-minute settlement implementation experience is any indicator, these cost estimates will have the potential to be much higher. It is also unclear how sensitive these figures are to change before net benefits from the IRP approach are negated entirely. That is, with no Cost-Benefit Analysis (CBA) having been undertaken or, at least, published to date.

The IRP approach would see all existing storage and hybrid system participants forced to apply to AEMO to change their registration category. This would occur on a reasonable endeavours basis within nine months after the rule takes effect. To ease participant burden, the AEMC has recommended that AEMO must not charge a fee for these changes. Although these timing and cost mitigation proposals seem appropriate, it is not clear whether there would be any impact on existing or future project commissioning as a result. If so, then this will also need to be factored into a comprehensive CBA.

EA notes that more than half of the IRP implementation costs result directly or indirectly from introducing the new participant category. These would be negated under Option 3 which would retain current participant categories. Although Option 3 would have implementation costs, prima facie, it is hard to see how they would be more expensive than the IRP approach.

Given Option 3 has largely the same benefits and could accommodate the move to any universal participant category that is implemented later, EA queries whether the IRP approach can be considered to be in the best economic interest of customers and market participants. We, therefore, suggest that if the AEMC has further information on costs and benefits that indicate the IRP approach is to be preferred, that this is made public. Doing so will counter any perception that customers are footing an inefficient bill for regulatory reform.

Charging Arrangements

The AEMC has decided to clarify elements of, rather than make any changes to, the existing Transmission and Distribution Use of System (TUOS/DUOS) frameworks for storage and hybrid facilities. This is on the basis that exempting storage would not be technologically neutral and would result in cross-subsidisation from other generators or loads. However, we do not consider such outcomes would result if the AEMC's preference to approach things on a service, rather than an asset, basis per other parts of the Draft Determination is also applied to charging arrangements.

Such an approach would see any storage asset, whether distribution or transmission connected, whose main purpose is providing generation or grid services, being exempt from TUOS and DUOS in line with the current treatment for generators and Market Network Service Providers (MNSPs)[1]. That is, where energy is *temporarily accumulated or used to ensure the later public provision of generation or security services*, rather than being *ultimately consumed for private end-use*.

Equalising storage and generation treatment in this manner would be consistent with other international developments. In the United Kingdom, the Office of Gas and Electricity Markets (OFGEM) has exempted storage facilities from Balancing System Use Of System (BSUOS) charges on imported electricity[2]. This follows changes made in the United States under FERC Order 841 that standardised the charging arrangements of energy storage resources and generators. The rationale was the same in both cases, but is best summarised by the latter:

"In response to the concern that transmission charges should not apply when an electric storage resources is dispatched by an RTO/ISO, we find that electric storage resources that are dispatched to consume electricity to provide a service in the RTO/ISO markets (such as frequency regulation or a downward ramping service) should not pay the same transmission charges as load during the provision of that service. We find that this would be consistent with the treatment afforded traditional generation resources that provide ancillary services, because they are not charged for their impacts on the transmission system when they reduce their output to provide a service such as frequency regulation down. Therefore, we find that electric storage resources should not be charged transmission charges when they are dispatched by an RTO/ISO to provide a service because:

> *(1) their physical impacts on the bulk power system are comparable to traditional generators providing the same service, and*

[1] Neither of these participant types pay TUOS for energy consumed to transport energy between regions or to support generation activity.
[2] See https://www.ofgem.gov.uk/cy/publications/cmp281-removal-bsuos-charges-energy-taken-national-grid-system-storage-facilities.

(2) assessing transmission charges when they are dispatched to provide a service would create a disincentive for them to provide the service"[3]

Taking such an approach would only help to make Australia a more attractive destination for the deployment of global storage investment capital. Moreover, it would alleviate other perversities of current arrangements. Chief amongst these being the effective double-charging of TUOS and DUOS when electricity is imported by storage, but which is later exported and consumed by end-use customers.

To better understand this situation, consider a solar farm that exports its energy to a load centre along a radial line. Under current arrangements, no TUOS or DUOS would apply. However, suppose a storage unit is connected between the solar farm and the load. Now TUOS or DUOS would apply to any energy sent from the solar farm that the storage unit imports. This results even if the same amount of energy is later delivered to the load and there is no change in line loading or utilisation. Moreover, it results even if the storage unit would have provided a net economic benefit to customers. For example, from:

- alleviating constraints, thereby allowing more generation to be dispatched;
- reducing evening peak prices by more than it increased daytime off-peak prices through intra-day arbitrage; or
- providing an alternative lever to solve problems of minimum demand that might otherwise see residential solar disconnected.

Aside from dead-weight economic loss impacts, current arrangements also undermine the business case for investment in, and actual utilisation of, storage technologies. That is, by increasing the operating margin that needs to be recovered to make storage viable against other investments.

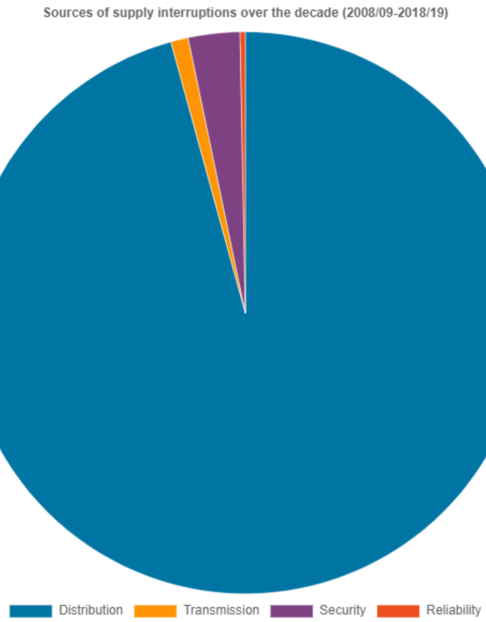
These perversities are further exacerbated by the potential for inefficient locational investment decisions introduced by differences in NSP rule interpretation and charging regimes. On this front, we acknowledge and appreciate the AEMC's clarification that storage and hybrid facility owners can seek charging outcomes on a negotiated basis. Further, that the principles to guide such negotiations are already included in sections 5.11 and 6.7 of the National Electricity Rules (NER). Unfortunately, however, this does little to provide certainty to investors with the outcomes of negotiations typically only coming late in the development cycle. Further, we highlight that even with such principles inconsistent treatment of storage has resulted. For example, as tabled in the Draft Determination, the Gannawarra battery is charged for consumed energy while others are not.

This might be an acceptable situation if such costs conferred some advantage. For example, by providing a measure of firm network access. Unfortunately, it does not. The Gannawarra battery faces the same risk of being constrained off as any other storage system or generator.

Such uneven treatment further erodes the investment case for storage. From an efficiency standpoint, this is particularly problematic for distribution networks. For as highlighted in the Reliability Panel's 2019 Annual Market Performance Review, it is within distribution networks that the most significant benefits to customers lie. That is, in the

[3] FERC Order 841, paragraph 294.

provision of system security services that can lower the incidence and severity of supply disruptions.



In general, EA agrees that technological neutrality and avoiding cross-subsidisation are principles consistent with best-practice economic theory. However, we do not see that these do, or should, apply in this case when viewed in light of the demarcation and examples provided above. The AEMC may disagree on this point, however, if so, these principles still need to be weighed against the principle of economic efficiency and the distortions that would be perpetuated, and the opportunities foregone, by retaining current charging arrangements.

In this regard, EA highlights that any decision to prioritise efficiency over other principles would not be without precedent. Indeed, the recent Final Determination on Dedicated Connection Assets is an excellent example, where a reduction in contestability was considered necessary to achieve optimal economic efficiency. Given this and the other reasons listed above, we strongly encourage the AEMC to further consider the long-term consequences of not changing TUOS and DUOS settings at this time.

Non-Energy Cost Recovery And Other Issues

EA is supportive of the AEMC amending the non-energy cost recovery framework so that it occurs on a gross basis. We consider it will remove current inconsistencies in the Rules and create a level playing field for market participants. Further, that it represents a robust long-term solution to the issues of negative or low regional settlement.

EA also agrees with the general approach for DC-Coupled Systems. When designed at the outset with hybrid facilities in mind, DC-coupled systems can provide numerous cost-saving opportunities. For example, in terms of spares holdings, cooling apparatus and monitoring and control systems. Promoting flexible arrangements for registration and classification for these systems will incentivise uptake and contribute to the achievement of the National Electricity Objective.

In terms of other issues raised in the draft determination, EA considers no changes are required to:

- the performance standards measurement location;
- Marginal Loss Factor calculation methodologies; and
- Reliability Panel representation.

We note these issues have been either been the subject of recent reviews with current settings deemed appropriate or will be considered in more detail as part of dedicated forthcoming rule changes.

On the issue of Network Service Provider (NSP) owned batteries, EA strongly agrees that no asset, whether NSP owned or otherwise, should be given preferential treatment in the connection process. However, we question how this can be confidently achieved given the opaque nature of negotiated connection arrangements in general, and between an NSP and its subsidiary entities in particular. Although acknowledging the ring-fencing guidelines review is ongoing, depending on its outcomes, there may still be a need for further Rules-based protections to ensure that consistent, transparent pricing and connection outcomes are seen NEM-wide. We, therefore, encourage the AEMC to commit to re-examining this issue post conclusion of the ring-fencing review.