16 September 2021

Joel Aulbury
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2001

Lodged via: https://www.aemc.gov.au/contact-us/lodge-submission

Dear Mr Aulbury

RE: Integrating energy storage systems into the NEM (ERC0280)

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC's) draft determination on integrating energy storage systems into the National Electricity Market (NEM).

About Shell Energy in Australia

Shell Energy is Australia's largest dedicated supplier of business electricity. We deliver business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers. The second largest electricity provider to commercial and industrial businesses in Australia[1], we offer integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. We also operate 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and are currently developing the 120 megawatt Gangarri solar energy development in Queensland. Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy.

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Overview

Shell Energy considers the draft determination to have some positive aspects. For example:

- The AEMC's proposed approach for non-energy cost recovery is in line with the 'causer pays' principle, and will more fairly and equitably account for bi-directional flows.
- We welcome the ability of Small Market Aggregators to provide ancillary services.

However, we believe the draft determination could be improved in a number of areas.

- Our primary concern is that flexible scheduled loads, including energy storage systems (ESS), may remain exposed to inefficient transmission charges. This deters efficient ESS investment and works counter to the National Electricity Objective (NEO). We believe this issue could be partially addressed in the near term by providing greater clarity that any scheduled load seeking an interruptible negotiated transmission service should face a cost-reflective price consistent with what the transmission network service provider (TNSP) charges to similar loads. In the long term, we believe that the current

[1] By load, based on Shell Energy analysis of publicly available data.
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2020.

transmission use of service (TUOS) pricing methodology also needs amendment. To implement our technology-neutral solution, we recommend that:

  - the AEMC makes minor changes to the National Electricity Rules (NER) to improve clarity
  - the final determination recommends the Australian Energy Regulator (AER) should urgently review its transmission Pricing Methodology Guidelines and Cost Allocation Guidelines.

- It is possible the new Integrated Resource Provider (IRP) participant category and the concept of an Integrated Resource Unit (IRU) could better-facilitate integrated operation of hybrid facilities. However, we believe there are a range of outstanding issues that must be addressed. For example, it is not clear that the benefits of the proposed dispatch arrangements (which would allow hybrids to comply with unit-level dispatch instructions on aggregate under most circumstances) would outweigh the costs for the Australian Energy Market Operator (AEMO), TNSPs and participants to implement them. We recommend a detailed cost-benefit analysis to assess this issue. We also recommend the AEMC considers alternative options to facilitate the smooth operation of hybrids.
- We recommend that the ESB reviews the NER sections that relate to generator performance standards (GPS). In particular, we believe the NER should clarify that: if modifying or adding plant to an ESS, generation or hybrid facility does not impact the facility's currently registered technical performance standards at the connection point, then the GPS should not be re-opened for negotiation. This would remove barriers to ESS, including business models that rely on adding storage (MWh) over time without changing the control system or inverter.

The remainder of this submission provides more detailed feedback on the draft determination, including the above issues.

Transmission charges

Defining the problem

In our 2020 submission to the ERC0280 consultation paper, we advocated for ESS to be exempt from TUOS charges "until such time as efficient TUOS pricing structures exist"[3]. We acknowledge that the AEMC disagrees that there should be technology-specific exemptions in the regulatory framework, even on a temporary basis. We agree with the general premise of a technology-neutral approach. However, we believe the draft determination does not address several underlying technology-neutral issues relating to TUOS (for prescribed transmission services) and charges for negotiated transmission services.

<u>TUOS for prescribed transmission services</u>

The NER provides clear guidance on TUOS charges, including that they "must be based on demand at times of greatest utilisation of the transmission network" (NER 6A.23.4) and have regard to "the role of pricing structures in signalling efficient investment decisions and network utilisation decisions" (NER 6A.25.2)[4]. In our view, TNSPs' existing TUOS pricing structures appear inconsistent with these requirements because they don't take into account whether a connecting load will be drawing from the grid at times of peak local demand or network congestion. This results in inefficiently high prescribed TUOS charges for flexible scheduled load that is willing to

[3] ERM Power, *RE: Integration of storage into the NEM*, 19 October 2020, pp 2-3. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/erm_power_7.pdf

[4] We disagree with the AEMC's argument that whole-of-system access reforms are the best way to encourage efficient investment decisions in the context of efficient storage location (pp 113 of the draft determination). Regardless of any access reforms, the NER is clear that TUOS pricing structures should have regard to signalling efficient investment.

be constrained down/off during times of local peak network utilisation. This will reduce the deployment of flexible scheduled load to below efficient levels.

The inefficiency is relevant to all flexible scheduled loads (regardless of their technology) because it relates to the firmness of the transmission service they require. ESS are the first technology encountering the issue of potentially inefficient TUOS structures; however, we believe that hydrogen electrolysers, and other 'smart' industrial loads will be sub-optimally deployed due to the same inefficiencies within the next decade.

As we noted in our 2020 submission to the consultation paper, it is possible that the AER could address this issue by reviewing and enforcing its TNSP Pricing Methodology Guidelines so that all load (including flexible scheduled load) was charged more cost-reflective TUOS (in line with Rules 6A.23.4 and 6A.25.2). We will share our concerns with the AER. However, we note that any review process may be lengthy. After the review itself, implementation may be protracted (e.g. aligned with the beginning of the next five-yearly regulatory period for each TNSP). If nothing is done in the interim, there will continue to be an inefficiently low deployment of flexible scheduled load – particularly for projects where TUOS materially impacts commerciality. In the case of ESS, this may have flow-on impacts to the rest of the electricity system, because of the valuable services ESS provides.

<u>Charges for negotiated transmission services</u>

To avoid inefficiently high TUOS charges, flexible scheduled load may seek to connect via a negotiated transmission service, rather than a prescribed transmission service. However, a flexible scheduled load proponent bears the risk that:

- the TNSP may set a price that is higher than what is cost-reflective
- the TNSP may impose unreasonably onerous non-price conditions
- the TNSP may offer different pricing to different proponents seeking the same type of negotiated services (e.g. competing ESS projects), which could disadvantage the proponent compared to its competitors.

We acknowledge that several NER clauses aim to address these issues – particularly in Schedule 5.11 (clauses 1, 5, 9 and 11) and 5.2A.6(b). However, there is no explicit mention of whether the TNSP or the AER (which publishes and enforces guidelines with which the TNSP must comply) must consider whether the negotiated transmission service is interruptible. This is a source of uncertainty that acts as a barrier for all flexible scheduled load (including ESS), since what is 'cost-reflective' and 'reasonable' differs depending on whether the service is firm or interruptible. I.e. because the NER do not explicitly require TNSPs to make this distinction, connection applicants are put at a disadvantage when they seek to negotiate their transmission service. This issue will become more pronounced as additional flexible load enters the market (e.g. merchant ESS not co-developed by TNSPs).

For the avoidance of doubt, we are not suggesting that TNSPs don't currently comply with the generalised interpretation of the relevant NER clauses. However, we consider that it would be beneficial to reduce uncertainty for flexible scheduled load proponents by explicitly providing guidance on interruptible negotiated transmission services. Like the above TUOS issue, this is a challenge that relates to the services sought by a connecting load, not the load's technology.

<u>Scope of the AEMC's decision</u>

AEMO's original rule change request was for ESS to be made exempt from TUOS charges. Shell Energy has heard speculation that the AEMC may choose to reject this request (as per the draft determination), but take no action on the underlying issues we have set out above, because they aren't in scope of the rule change process.

We strongly believe that the transmission-related challenges we've laid out are in scope. While they are relevant to all flexible scheduled load, it is their impact on ESS that ultimately led to AEMO's original rule change request. Therefore, we believe our proposed solution (discussed below) is also in scope, and should be implemented without requiring a separate rule change process. In our view, the changes we suggest are necessary to remove the uncertainty around transmission charges for flexible scheduled load, as per the intention of AEMO's original rule change request. In our view, this is not achieved by the current draft determination and should be a priority outcome from this rule change process.

Our proposed solution

We offer a three-part solution to addressing these challenges through the ERC0280 final determination.

1. The first part is to make minor NER amendments to provide more clarity around the process of negotiating a negotiated transmission service that allows for a scheduled load to be interrupted.
2. The second part is to recommend the AER should urgently review its transmission Pricing Methodology Guidelines (relevant to TUOS) and Cost Allocation Guidelines (relevant to negotiated transmission service pricing).
3. The third part is to amend the NER to stipulate the AER must periodically update the transmission Pricing Methodology Guidelines and Cost Allocation Guidelines.

1a) NER amendment to define the concept of 'interruptible' negotiated transmission services

Our first suggested NER amendment is to define a sub-category of negotiated transmission service: an 'interruptible' service. We recommend a definition to the effect of:

> "An *interruptible network service* is a type of negotiated transmission service that may be interrupted under circumstances agreed by the connecting applicant and the TNSP."[5]

The intent of this definition is to capture the type of service required by a scheduled load willing to be constrained off during times of peak network utilisation or localised network congestion.

The National Gas Rules (NGR) set a precedent for defining an interruptible service. In particular, Rule 647 under Part 25 of the NGR defines 'lower tier' gas transmission services, which "include transportation services described in the natural gas industry as 'interruptible'". By specifying the difference between firm and interruptible services, the NGR enables gas market participants to more efficiently procure the services they need. There is an analogous argument for electricity system. I.e. if the NER explicitly acknowledge that there is a fundamental difference between a firm vs. interruptible negotiated transmission service, then it is easier for an interruptible service to be valued on a cost-reflective basis.

1b) NER amendment that the AER must explicitly consider interruptible services in its Cost Allocation Guidelines

Defining 'interruptible service' in the NER facilitates our next suggested amendment, which is to insert a new subclause in 6A.19.3 (after subclause (b)) to the effect of:

> "The Cost Allocation Guidelines must specify how interruptible services are to be addressed in a Cost Allocation Methodology, with reference to the negotiating principles in Schedule 5.11."

To further increase clarity, we suggest also amending Schedule 5.11 to explicitly reference how an interruptible service should be treated. In particular, we think that the price for an interruptible service should be lower than the price for the equivalent firm service, with the difference being proportionate to the need for additional

[5] We note that the AEMC may prefer to split up negotiated transmission services into two categories: ('firm' services and 'interruptible' services) to achieve a similar effect to what we describe here. However, this level of design detail is beyond the scope of our submission.

network infrastructure an equivalent firm service would place on the network. This could be achieved by inserting a new clause 2 as follows:

1 "The price for a negotiated transmission service should be based on the costs incurred in providing that service, determined in accordance with the principles and policies set out in the Cost Allocation Methodology for the relevant Transmission Network Service Provider."

2 "In determining the costs of providing a negotiated transmission service, and the accompanying terms and conditions, the Transmission Network Service Provider must have regard to whether the connection request is for an interruptible network service."

We consider that implementing the amendments to 6A.19.3 and Schedule 5.11 would greatly clarify that a flexible scheduled load proponent is able to negotiate an interruptible negotiated transmission service that:

- will have a cost-reflective price, with fair terms and conditions
- will be comparable to what a competitor could negotiate for a similar interruptible service.

As discussed below, we believe that our suggestions could result in more efficient market outcomes in a relatively short space of time, and should therefore be pursued as a priority.

<u>2a) Recommendation that the AER urgently reviews its Cost Allocation Guidelines</u>

As per the existing clause 1 of Schedule 5.11 (see above), the price a TNSP charges for a negotiated transmission service must comply with the TNSP's Cost Allocation Methodology, which in turn must comply with the AER's Cost Allocation Guidelines.

If the AEMC agrees to implement our suggested change to 6A.19.3, the AER will need to amend the Cost Allocation Guidelines. However, even if no change is made to 6A.19.3, we believe the Cost Allocation Guidelines should be updated. They have not been amended since they were originally published in 2007, and are demonstrably out of date. For example, the guidelines refer to a deleted NER clause (6A.9.1) when stipulating how TNSPs must prepare prices for negotiated transmission services[6].

We believe our proposed updates to the Cost Allocation Guidelines could flow through relatively quickly to each TNSP's respective Cost Allocation Methodology. After the AER updates the guidelines, it should take no longer than six months for TNSPs to make corresponding amendments to their methodologies (NER 6A.19.4(a)). These amendments should come into effect no longer than three months after the TNSPs submit them to the AER (NER 6A.19.4(g)). As a result, we believe that it would be faster to provide clarity around interruptible negotiated transmission services than to implement changes to TUOS charges (discussed below).

<u>2b) Recommendation that the AER urgently reviews its Pricing Methodology Guidelines</u>

Similar to our above suggestion for the Cost Allocation Guidelines, we believe the ERC0280 final determination should recommend that the AER must urgently review its Pricing Methodology Guidelines.

- As stipulated by NER 6A.25, a TNSP's TUOS charges must comply with the TNSP's Pricing Methodology, which must in turn comply with the AER's Pricing Methodology Guidelines.
- In our view, the guidance on TUOS pricing structures is no longer up to date. In particular, we believe that since 2014 (when the guidelines were last updated), the willingness and ability of different loads to operate more flexibly has greatly increased. We expect this trend to continue as technologies continue to develop, and the market becomes more two-sided. As they currently stand, the guidelines do not address this. Consequently, TNSPs' pricing methodologies have relatively blunt pricing structures that

[6] AER, *Electricity transmission network service providers, Cost allocation Guidelines*, September 2007, pp 12. Accessed from: https://www.aer.gov.au/system/files/Appendix%20B%20-%20cost%20allocation%20guidelines_0.pdf

result in inefficiently high charges to flexible scheduled loads that don't contribute to the requirement for more network expenditure.

- The guidelines reference NER clauses that have been deleted (e.g. 6A.23.4(j)).[7]

As observed earlier in this submission, we consider it likely that any updates to TUOS pricing structures would take substantial time to be implemented. This is because implementation would likely be aligned with each TNSP's 5-yearly regulatory reset. To avoid inefficient outcomes in the interim, it is crucial to also update the Cost Allocation Guidelines in the short term. Over the longer term, we believe our suggestions for both prescribed and negotiated transmission services should be enduring, because they address slightly different issues.

<u>3) NER amendments to require more regular updating of relevant guidelines</u>

We have already outlined our rationale for why the AER's Cost Allocation Guidelines and Pricing Methodology Guidelines should be urgently reviewed. However, we believe the issues necessitating an urgent review could have been previously anticipated and addressed if the guidelines were subject to regular review.

We therefore recommend adding a new subclause after NER 6A.19.3(e), to the effect of:

> "The AER must review the Cost Allocation Guidelines at least every five years, to align with the next regulatory period for each TNSP."

Similarly, we recommend adding a new subclause after NER 6A.25.1 (e), to the effect of:

> "The AER must review the Pricing Methodology Guidelines at least every five years, to align with the next regulatory period for each TNSP."

Making these changes would help to mitigate the risk that the regulatory framework fails to keep pace with the market as it continues to evolve (e.g. with respect to the anticipated growth in flexible scheduled loads and 'smart' energy resources). To emphasise this point, we observe the market has changed substantially since the Cost Allocation Guidelines were published in 2007, and the Pricing Methodology Guidelines were published in 2014.

Distribution charges

Shell Energy considers that the arguments we have outlined for transmission charges broadly apply to distribution use of system (DUOS) charges. I.e. we believe that all load connected to a distribution network should receive cost-reflective network charges, which should have regard to whether the load will be drawing from the grid at times of peak local demand. This should apply to both negotiated and regulated distribution services.

We note that DUOS reform has been an area of active consideration by the AER, and that some distribution network service providers (DNSPs) have implemented regulated tariff structures that are reasonably efficient. For example, as highlighted in our October 2020 submission,[8] Ausgrid's sub-transmission capacity charges apply only 2-8pm workdays. This structure provides appropriate incentives for load to operate flexibly at times of (typically) peak network demand.

Conversely, some DNSPs still appear to have inefficient tariff structures. For example, Powercor levies demand charges based on maximum demand, regardless of whether time of use coincides with higher local network

[7] AER, *Electricity transmission network service providers, Pricing methodology guidelines,* 17 July 2014, pp 4. Accessed from https://www.aer.gov.au/system/files/AER%20-%20Transmission%20pricing%20methodology%20guidelines%20-%2017%20July%202014_4.pdf

[8] ERM Power, *RE: Integration of storage into the NEM*, 19 October 2020, pp 4. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/erm_power_7.pdf

demand. The Gannawarra battery knowledge sharing report[9] outlines how this results in inefficient battery charging operations. We consider that this inefficiency extends to all flexible scheduled load – not just ESS. As the market becomes more two-sided, the materiality of this inefficiency will increase.

As a result, we recommend that the AEMC reviews Chapter 6 of the NER, and considers making equivalent clarifications to what we have suggested for transmission charges. Similarly, we suggest that the final determination recommends that the AER reviews the relevant AER guidelines (e.g. the distribution cost allocation guidelines[10] and the Electricity Distribution Service Classification Guideline[11]) to assess whether there is sufficient guidance for how DNSPs should treat flexible load.

Details of the proposed IRP framework

Dispatch instructions for hybrid facilities

The draft determination proposes a dispatch process whereby a hybrid facility would be issued individual unit-level dispatch instructions, but:

- under normal operating conditions, the hybrid facility would only need to comply with these dispatch instructions in aggregate at the connection point
- under a set of operating conditions to be defined by AEMO, the facility would need to comply with the instructions at the individual unit (DUID) level.

We are concerned that implementing such a process would be complex and costly. In practice, we expect it would entail AEMO issuing two 'types' of unit-level dispatch instructions: one where each individual unit would have to comply, and another where the hybrid operator would be able to comply in aggregate. This would require a significant systems overhaul for AEMO, Network Service Providers[12] and participants. It is not clear that the limited benefits achieved by such a change would outweigh the costs.

The use of aggregate dispatch at the connection point may also cause issues in relation to hybrid facilities providing Frequency Control Ancillary Services (FCAS) and primary frequency response. We have thought of several examples, but there may be more.

1. Consider a hybrid facility that contains scheduled load with a degree of variable consumption. For this type of facility, it may be challenging to accurately measure the contribution of the FCAS-supplying component at the connection point. As a result, FCAS provision would need to rely on measurement at the FCAS-supplying component's terminals. I.e. dispatch compliance would need to be measured at the individual unit level, not at the connection point. This is inconsistent with the proposed model, where dispatch compliance would be measured at the connection point in most circumstances.
2. Calculating FCAS trapezium limits for a hybrid facility based at the connection point will present significant challenges. For example, for a wind farm/BESS hybrid with measurement at the connection point, the limits applicable to the FCAS trapezium are associated with both the BESS and the unconstrained intermittent generation forecast (UIGF) for the wind farm. Inaccurate UIGF calculations could result in the hybrid facility's inefficient dispatch in both the energy and regulation FCAS markets, because the FCAS trapezium could limit (or trap) the combined BESS/wind output. In this case, the

[9] *Edify Energy and EnergyAustralia, Gannawarra Energy Storage System: Operational Report #1 and #2,* September 2020. Accessed from: https://arena.gov.au/assets/2020/09/gannawarra-battery-energy-storage-system-operational-report.pdf

[10] AER, *Electricity distribution network service providers: Cost allocation guidelines*, June 2008. Accessed from: https://www.aer.gov.au/system/files/Distribution%20cost%20allocation%20guidelines%20and%20Victorian%20guidelines%20%2826%20June%202008%29.pdf

[11] AER, *Electricity Distribution Service Classification Guideline*, September 2018. Accessed from: https://www.aer.gov.au/system/files/AER%20-%20Service%20Classification%20Guideline%20-%2028%20September%202018.pdf

[12] This notes that AEMO dispatch requirements and dispatch monitoring systems are often provided to participants via NSP facilities.

inefficiency can only be resolved if the wind farm and BESS components were individually bid and dispatched as separate DUIDs. For the avoidance of doubt, this is what currently happens; but it is inconsistent with the proposed aggregated dispatch compliance.

3. Under the current framework, a BESS does not need to supply mandatory narrow band primary frequency response unless it is generating active energy dispatch. It is not clear how this provision could be maintained unless dispatch compliance continues to be assessed at the unit level. This is inconsistent with the proposed framework.

Other than for GPS assessment and compliance measurement, we question the value to participants of the proposed framework for AC-connected hybrid facilities. We even question if an overall connection point GPS assessment will be practically achievable, given the differing performance standards applied to different technologies, as stipulated in some areas of the NER. We believe the AEMC should undertake further detailed work on this issue prior to a final determination.

In conclusion, the proposed dispatch arrangements for hybrids create a range of unintended consequences. The proposed arrangements would introduce costs, but the benefits are unclear. We recommend a detailed cost-benefit analysis to determine whether the expected benefits would outweigh the costs.

DC-coupled hybrid facilities

Figure 2.3 of the draft determination outlines the AEMC's proposal for DC-coupled hybrid facilities to have three different classification options. We suggest several changes to the 'semi-scheduled generating unit' option to remove what appear to be unintended consequences of the proposed framework.

1. Require every dispatch instruction issued to the hybrid facility to be a *semi-dispatch interval*. Implementing our suggestion would effectively limit the facility's output to the UIGF at all times. As it stands, the draft determination appears to allow the facility to operate in an unconstrained manner by using any DC-coupled controllable component (e.g. BESS) during intervals that are not *semi-dispatch intervals*. This effectively allows the ESS to flexibly respond to unforecast high prices in *non-semi-dispatch intervals* absent issue of a dispatch instruction by AEMO. This does not match our understanding of the AEMC's intent, which we believe is aimed at improving outcomes for semi-scheduled generators that choose to increase the firmness (dispatchability) of their output by coupling with a controllable ESS. We believe our suggestion would be best incorporated by amending the existing subclause 4.9.5(a).

2. Require the registered capacity of the facility to be capped at the size of the intermittent generator(s). This would complement our first suggestion by clarifying that the 'semi-scheduled generating unit' categorisation for DC-coupled production units (hybrids) is not a loophole for a flexible ESS to be able to operate on a semi-scheduled basis if connected to a VRE generator. We believe the proposed new subclause 2.2.7(c1) would be an appropriate place to incorporate this suggestion.

   If the AEMC does not accept this suggestion, we recommend that 2.2.7(c1) should set a requirement to the effect of "the significant majority of the generating plant comprised in the IRU must be intermittent". The intent of this alternative is the same as our primary suggestion.

3. Allow the facility to consume from the grid as a semi-scheduled load. Regardless of whether the facility's consumption is auxiliary load, charging or another load, consumption at the connection point should be subject to *semi-dispatch interval* dispatch instruction. In this case the *semi-dispatch interval* dispatch instruction would set a cap on the active energy that could be consumed at the connection point.

A participant who wanted to make use of the full capabilities of a DC-coupled intermittent generator(s) and an ESS would still be able to do so via use of the Figure 2.3's first option ('Scheduled IRU') or third option ('Multiple Classifications').

Bidding parameters

The draft determination indicates that a scheduled IRU will be afforded the use of 20 bid bands, (10 bands for generation and 10 bands for scheduled load). However, this does not fully mimic the existing bidding arrangements for an ESS bidding as both a generator and scheduled load. Shell Energy recommends that the final determination allows an IRU to provide:

- separate maximum and projected assessment of system adequacy (PASA) availability values
- separate up and down ramp rates for dispatch as a generator (i.e. when providing active energy) and as a scheduled load (consuming active power).

The current ability to provide separate bid values in these areas when acting in generation or scheduled load mode enables participants to efficiently optimise bidding and dispatch outcomes, and should not be removed as part of this rule change. Removing these separate parameters would result in less efficient dispatch outcomes and additional costs to consumers.

We also question the need and the practicality of new draft subclauses 3.7.3(e)(5), 3.8.4(c)(3A) and 3.8.6(g2). It is unclear what the intent or practical application of this new clause could be for a scheduled IRU that has the ability to replenish storage capacity across the day. It is almost certain the obligations imposed by these new subclauses will constitute an unmanageable 'compliance trap'.

As presented in its current form, the IRP when compiling its day ahead bids would need to provide input values of where it considers energy may be dispatched across all 228 trading intervals in a trading day where an IRP may not be best placed to do so. This is analogous to a delivery driver being required by law to submit the night before an available fuel forecast for every 5 minutes of their delivery day to a central authority, when each subsequent delivery only becomes known once the current delivery has been completed and access to refuelling stops are unknown.

These unworkable obligations may result in unnecessary declaration of low reserve conditions by AEMO and unnecessary and costly dispatch of the reliability and emergency reserve trader (RERT) mechanism. Shell Energy considers that the current provisions whereby a scheduled IRU would be required to provide a daily nominal energy constraint (in the same way as any other fuel-constrained resource provider) remains sufficient for AEMO's reliability assessment requirements under Chapter 3 of the NER. Therefore, we recommend that the draft subclauses 3.7.3(e)(5), 3.8.4(c)(3A) and 3.8.6(g2) are removed from the final rule.

We are also concerned by the proposed change to NER subclause 3.7.2(f)(1) which would require AEMO to include estimates of load consumption by an IRU at times of peak demand. We consider this is inconsistent with the requirements of subclause 3.7.2(1)(c)(ii), where load consumed by scheduled load is excluded from the daily peak demand calculation. We recommend no adjustment to subclause 3.7.2(f)(1) to include load consumed by an IRU. Instead, we recommend additional clarity to clause 3.7.2(1)(c)(ii) to ensure that, similar to other scheduled load, IRU consumption is excluded from the peak demand forecast.

Transitioning to the IRP regime

"The draft rule requires existing storage participants to apply to AEMO to change their registration category to IRP and to reclassify their storage systems". Although the draft determination specifies that the AEMC "does not consider that this application process will require the re-negotiation of a participant's performance standards", it does not appear as though the AEMC's view is enshrined in the draft rule. To ensure clarity, we recommend that the NER explicitly states that AEMO cannot automatically re-open performance standards as ESS transitions to the IRP category.[13]

More broadly, we question the rationale for why all ESS >5 MW capable of linear ramping must register as an IRU with a single DUID, rather than a scheduled generator/load (with two DUIDs). We consider that there may be situations where an ESS operator would prefer their plant to be registered as a scheduled generator/load rather than an IRU. Therefore, we recommend that existing and future ESS participants are given the choice of registering as an IRU or a scheduled generator/load pair.

Retrofitting and generator performance standards

At the information session on 2 August 2021, the AEMC confirmed that, where an existing plant is 'retrofitted' with an ESS, it would be up to AEMO and the relevant NSP as to whether the GPS needed to change. While this may be required for technical reasons in some circumstances, Shell Energy believes that, if an existing plant is upgraded such that the technical characteristics at the connection point remain unchanged, then the market participant should not be required to reopen their performance standards. We believe this principle should apply regardless of the underlying technology. This would be consistent will the practical application of NER 5.3.9 for upgrade of traditional generation technologies (e.g. turbine upgrades).

In the context of ESS or hybrid projects, adding storage (i.e. MWh) behind an existing inverter is a case in point. Market participants are currently disincentivised to increase the storage duration of their assets (or design projects for future upgrades) because doing so may trigger a review of their performance standards, which would introduce cost and uncertainty. As the energy transition continues, we consider this will result in inefficient deployment of incremental storage additions.

To address this issue, we recommend that the AEMC updates NER 5.3.9 to clarify the situations where altering a generator or IRP does not require a reopening of its GPS. This would ensure that participants are not requested to reopen their GPS unnecessarily.

Recovery of non-energy costs

Shell Energy supports the AEMC's proposal for non-energy cost recovery to be based on gross (not netted) consumed or sent out energy, regardless of a participant's registration category. We believe that this new framework is in line with the 'causer pays' principle, and will more fairly and equitably account for bi-directional flows.

However, as raised in our submission[14] to ERC0327 (Settlement under low operational demand), we disagree that amending the non-energy cost recovery framework will "provide a permanent resolution for the settlement and equity issues raised by AEMO and Infigen"[15]. In particular, if the ERC0326 rule change (NEM settlement under low, zero and negative demand conditions) is not enduring, there will be nothing to prevent net-positive loads paying a disproportionate amount of non-energy costs during intervals of low operational demand.

Our rationale is that, even under the new cost-recovery regime, there will still be intervals with low operational demand. In these intervals, market participants with net-consumption at their connection point will be exposed to the corresponding non-energy costs. When spread between a small number of participants, these costs could be material. In addition to being detrimental to the impacted participants, this may incentivise unintended behaviour. For example, an impacted participant may choose to reduce consumption (or turn on behind-the-meter generation) to avoid the non-energy costs. This in turn would increase the challenges for AEMO operating

[13] Ibid, pp 75

[14] Shell Energy, *RE: Settlement under low operational demand (ERC0327)*, 29 July 2021. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/shell_0.pdf

[15] AEMC, *Integrating energy storage systems into the NEM, Draft rule determination*, 15 July 2021, pp 87

a "low demand" power system, and the burden for the remaining market participants with net-consumption. We consider it likely that there would be scenarios where the exposed market participants would be saddled with costs far above the 'causer pays' principle.

We are also concerned that some facilities under the draft rule may continue to benefit from the provision of non-energy services without contributing to their cost. To illustrate this point, consider a facility with balanced behind the meter consumption and generation. This facility would not incur non-energy costs, but would still benefit from:

- the provision of both raise and lower contingency FCAS in the event of trip of either its load (lower FCAS) and generation (raise FCAS)
- the general provision of system restart ancillary services (SRAS)
- (potentially) network support and control ancillary services (NSCAS)
- (in the future) the provision of new ancillary services for which there is currently no market.

In summary, Shell Energy recommends that the AEMC does not rely solely on ERC0280 as the long-term solution to the issues raised in ERC0326 and ERC0327. We are also concerned that the draft rule will not result in the equitable cost recovery from all facilities that benefit from the provision of these services. We would be pleased to discuss this further with the AEMC if further clarification would be useful.

Timeframes

We consider that implementing our proposed suggestions relating to transmission charges should be a priority, regardless of the implementation timeframes for the rest of the actions arising from the AEMC's final determination. This argument extends to DUOS charges, though we consider transmission charges to be a more urgent issue.

More broadly, we recommend the AEMC considers bringing forward the proposed April 2023 commencement date for the full reform package. Doing so may realise benefits earlier (e.g. by enabling ESS to better work as part of hybrid projects). Similarly, faster implementation may reduce costs in some instances. For example, under the draft determination, each BESS >5 MW must register as an IRU; therefore, if a BESS is built between now and April 2023, it would need to implement two bidding systems – one for the existing arrangements (i.e. two DUIDs), and one for the new arrangements (a single DUID). This would incur greater costs than if it only had to implement a single bidding system.

Retailer reliability obligation (RRO)

The draft determination states that an IRP would be "a liable entity under the RRO if its load exceeds 10 GWh in a particular NEM region in a year". It goes on to clarify that an IRP's aggregate load for the purpose of RRO liability "would be calculated with reference to its generation as well as its load". For an ESS, this means that its generation would be netted from its load.[16]

This has several implications.

- Whether a standalone ESS is categorised as an RRO liable entity depends on its round-trip efficiency and yearly generation. This gives a perverse incentive for smaller ESS because they are less likely to be impacted by the RRO. For example, an ESS with 90% round-trip efficiency would need to be generating 90 GWh per year to hit the 10 GWh threshold. Assuming operation equivalent to daily 2-hour cycles (a plausible scenario over the next decade), the maximum capacity to fall under the

[16] Ibid, pp 123-124

threshold would be ~123 MW. If we consider the same scenario but 85% round-trip efficiency, the maximum yearly output reduces output to ~57 GWh, and the maximum capacity for daily 2-hour cycles reduces to ~78 MW.

- It is plausible that it would be efficient for a single IRP to be responsible for multiple ESS projects. However, the more ESS projects that sit under a given IRP for a given region, the more likely the IRP is to meet the 10 GWh threshold. Therefore, the draft determination may unintentionally incentivise an inefficiently high number of separate IRPs (or equivalently, an inefficiently low number of IRUs per IRP).

We acknowledge that the RRO liability for an ESS would only apply if the ESS was charging during a reliability event, which is something within the ESS's control. On face value, this lends itself to an argument that RRO compliance costs for an ESS are immaterial. However, being a liable entity under the RRO could prevent an ESS's efficient provision of ancillary services that would involve charging (e.g. contingency lower FCAS caused by a large load tripping during a heatwave-induced reliability event, or the ongoing provision of regulation lower services). Further, given the uncertainty around what the RRO will look like in the future (e.g. due to changes resulting from the Post-2025 reforms), there is a risk that being categorised as a liable entity has unintended consequences. Therefore, we recommend that ESS should not be captured as a liable entity under the RRO.

Conclusion

While the draft determination has promising elements, Shell Energy believes that there are a range issues that require further consideration. Our primary concern is that flexible scheduled loads, including ESS may remain exposed to inefficient transmission charges under the draft determination. We have recommended a path forward to address this issue, which includes small, clarifying amendments to the NER. We consider this to be a time-sensitive issue, because it is resulting in inefficiently low deployment of flexible load.

We have also made suggestions to improve other parts of the draft determination. The most notable of these secondary suggestions relate to the dispatch of hybrid facilities, onerous compliance for IRU operation, and performance standards when adding storage. In particular, it is unclear that the proposed framework for hybrid facilities will deliver a net-benefit to the NEM, given what could be substantial implementation costs and unintended consequences. We recommend the AEMC undertakes a detailed cost-benefit analysis prior to the final determination.

If you would like to discuss this submission further, please contact Matthew Ladewig, Policy Adviser at matthew.ladewig@shellenergy.com.au or on 03 9214 9397.

Yours sincerely

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