7 October 2021

Paul Harrigan
Australian Energy Regulator
GPO Box 520
Canberra ACT 2601

Lodged via email: AEMO2021@aer.gov.au

Dear Mr Harrigan

RE: Proposed negotiated transmission service criteria for AEMO

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Regulator's (AER's) call for submissions on the negotiated transmission service criteria (NTSC) to apply to the Australian Energy Market Operator (AEMO) in its function as a Victorian transmission network service provider (TNSP).

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.

www.shellenergy.com.au

Overview

Shell Energy recently made a submission[3] to the Australian Energy Market Commission (AEMC) in response to its draft determination on the 'integrating energy storage systems' rule change (ERC0280)[4]. In our submission to the AEMC, we made suggestions relevant to the AER's consultation on the Negotiated Transmission Service Criteria (NTSC) to apply to AEMO:

1. The AEMC should make minor National Electricity Rules (NER) amendments to provide more clarity around the process of negotiating a transmission service that allows for a scheduled load to be interrupted.
2. The AEMC should recommend that the AER urgently reviews its Cost Allocation Guidelines, in the context of ensuring that interruptible scheduled load is charged cost-reflective prices.

[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.
[3] Shell Energy, *RE: Integrating energy storage systems into the NEM (ERC0280)*, 16 September 2021. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/a31._shell.pdf
[4] AEMC, *Integrating energy storage systems into the NEM*. Accessed from: www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

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Our rationale for these suggestions is that the current regulatory regime causes unnecessary uncertainty and risk for flexible load proponents. This results in inefficiently low deployment of flexible scheduled load, at a time where it should be encouraged to enable a smoother energy transition.

We consider our suggestions to be relevant for all jurisdictions, including Victoria. Therefore, we recommend that the AER applies them in the context of Victoria's NTSC. In doing so, we suggest that the AER collaborates with the AEMC. However, we believe that the AER could implement our recommendations independently of the AEMC's final determination on ERC0280. This is because our suggestions are consistent with the existing NER – they simply provide valuable clarity.

Negotiated transmission services for interruptible scheduled load

Defining the problem

To avoid inefficiently high transmission use of service (TUOS) charges (discussed below), flexible scheduled load may seek to connect via a negotiated transmission service, rather than a prescribed transmission service. However, a flexible scheduled load proponent negotiating their transmission service 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 energy storage system (ESS) projects), which could disadvantage the proponent compared to its competitors
- the price does not become known until quite late in the project timeline, creating needless uncertainty during the development phase.

We acknowledge that several NER clauses aim to address some of these issues – particularly in Schedule 5.11[5] (clauses 1, 5, 9 and 11) and 5.2A.6(b). In Victoria's case, the proposed NTSC largely mimics the negotiating principles in Schedule 5.11. 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 transmission service is firm or interruptible. Because the NER (and proposed NTSC) do not explicitly require TNSPs to make this distinction, connection applicants are put at a disadvantage when they seek to negotiate their transmission service.

In addition to disadvantaging proponents during negotiations, the lack of guidance for interruptible scheduled load introduces risks as part of the development process. To understand how, consider the example of impacts on an ESS developer.

- The developer must choose the projects in which it will invest its time and resources. For any given project, this typically involves developing a preliminary business case. Transmission charges are a key input to this business case. However, under the current regulatory regime, the developer has no clarity on the charges it will face, because the TNSP could interpret the rules on negotiated services in a range of ways.

[5] Throughout this submission, we refer to Schedule 5.11 of the current NER (version 171), which contains negotiating principles for negotiated transmission services. The current Schedule 5.11 is an updated version of 6A.9.1 in version 109 of the NER, to which the AER's consultation paper refers. To avoid confusion, the NER references we make are all for the current version, not version 109.

- Price discovery for transmission charges does not occur until after the proponent begins negotiations with the TNSP. However, it is not practical to have these negotiations until the project has been sufficiently developed. Getting to this point cannot occur until material development costs (which can be circa 5% of project value) are sunk.
- If the developer's transmission cost assumptions (on which its preliminary business case was founded) were too optimistic, then the project can be discontinued at this point. In this case, the cost to the developer is the sunk cost, plus the cost of missed opportunities it would otherwise have been pursuing. Conversely, it is possible that excessively pessimistic transmission cost assumptions could prevent viable projects from meeting the preliminary business case hurdle. Either of these outcomes is inefficient.
- This inefficiency is a market failure caused by imperfect information being available to the developer. It could be mitigated if there was clearer guidance on the charges for interruptible transmission services.

The above issues will become more pronounced as additional flexible scheduled load enters the market (e.g. merchant ESS not co-developed by TNSPs). Until it is resolved, we believe there will be inefficiently low deployment of flexible scheduled load. In the case of ESS, this may have flow-on price and reliability impacts to the rest of the electricity system, because of the valuable services ESS provides.

For the avoidance of doubt, we are not suggesting that TNSPs don't currently comply with the generalised interpretation of the relevant NER clauses (and, in Victoria's case, the NTSC). 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. This is relevant to all jurisdictions, including Victoria – hence this submission as part of the NTSC consultation process.

Finally, while we acknowledge that the existing dispute resolution process has value, it is intended as a mechanism of last resort, and comes at additional costs to participants and TNSPs. It would be far more efficient if there was clear guidance relating to flexible scheduled load, rather than relying on the dispute resolution mechanism to facilitate fair negotiations.

Our proposed solution

In our submission to the AEMC's ERC0280 draft determination, we recommended a multi-step solution to address the above issue for negotiated transmission services. While our proposed solution includes changes to the NER, we believe that the AER could independently adopt our suggestions, since they are consistent with the existing NER, but serve to provide additional clarity.

1) Define the concept of 'interruptible' negotiated transmission services

The first step of our solution 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."[6]

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

While we have suggested that the AEMC includes this definition in the NER, the AER could independently include it in the NTSC and/or the Cost Allocation Guidelines.

[6] We note that it may be appropriate 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 design choice is beyond the scope of our submission.

2) Explicitly consider interruptible services in the Cost Allocation Guidelines

Defining an 'interruptible service' facilitates our second suggestion: for the Cost Allocation Guidelines to specify how interruptible services are to be addressed in a Cost Allocation Methodology, with reference to the negotiating principles in Schedule 5.11 (and, in Victoria's case, the NTSC).

If the AER chose not to update the Cost Allocation Methodology, then in Victoria's case, our intent could be achieved by adding an equivalent clause directly into the NTSC.

3) Include a new clause in Schedule 5.11 (and in Victoria's case, the NTSC)

To complement our second suggestion, we have recommended that the AEMC amends NER 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 additional load an equivalent firm service would place on the network, and the need for this to be considered in network planning. This would take into account the capability retained in the network to connect additional load, as facilitated by the flexibility of the interruptible scheduled load. We believe our intent 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 recommend that the AER reflects our suggested amendment to Schedule 5.11 in the NTSC.

When combined with our previous suggestion, we believe that this 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.

In our view, this would help to address the negotiating power imbalance that is inherently skewed in favour of the TNSP.

4) Conduct a broader review of the Cost Allocation Guidelines

As per the existing clause 1 of Schedule 5.11 (see above; relevant to states other than Victoria), 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. The proposed NTSC has a similar provision for Victoria:

5 "The price of a negotiated transmission service must reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology."

We consider this to be an important provision. However, we observe that the Cost Allocation Guidelines 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[7]. Therefore, regardless of whether the AER accepts our second suggestion

[7] 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

(see above), we recommend that the AER reviews and updates the Cost Allocation Guidelines. We recommend that the AER explicitly considers the impacts to flexible scheduled load (e.g. ESS, 'smart' electric vehicle charging systems, hydrogen electrolysers, and other 'smart' industrial load) when undertaking this task.

We acknowledge feedback from the AER that reviewing the Cost Allocation Guidelines may be resource intensive, and the AER already has a full work program. However, we believe the issues we have raised in this submission are material and should be addressed. If the AER is unable to prioritise a full review due to resourcing constraints, then we recommend a targeted (and therefore less resource intensive) process to incorporate our suggestions. We believe this should be progressed as a matter of priority, regardless of whether it can be completed in time to align with the start of the next regulatory period for Victoria.

Updates to the Cost Allocation Guidelines could flow through relatively quickly to each TNSP's respective Cost Allocation Methodology. After the guidelines have been updated, 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)). In our view, this relatively fast implementation period would help to address inefficiently low deployment of flexible load in the near term.

5) Commit to periodically reviewing the Cost Allocation Guidelines

We have already outlined our rationale for why the Cost Allocation Guidelines should be reviewed as a matter of priority. However, we believe the issues necessitating an urgent review may have already been anticipated and addressed if the guidelines were subject to regular review.

We therefore recommend that the AER commits to reviewing the guidelines at least every five years, to align with the 5-yearly regulatory reset cycle for TNSPs.

Periodically reviewing the guidelines 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.

A related topic: inefficient TUOS charges for prescribed transmission services

Although the AER focused this consultation solely on negotiated transmission services, we believe the AER should also review how it regulates TUOS for prescribed transmission services. As for negotiated transmission service charges, we are concerned that TUOS charges are inefficiently high for flexible scheduled load. This directly impacts on negotiated transmission service negotiations, because a proponent's only alternative is to connect via a prescribed transmission service.

For the avoidance of doubt, we encourage the AER to address inefficient charges for both prescribed and negotiated transmission services.

Defining the problem

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). 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[8].

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 AER 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. This results in inefficiently high TUOS charges for loads with low (or no) demand at times of greatest utilisation of the transmission network. This represents non-compliance with several NER clauses (see above). It has the greatest impact on flexible loads that are willing and able to stop consumption during times of local peak network utilisation or congestion. The inefficiency is compounded due to the broader benefits flexible load delivers to the electricity system.

In summary, the NER clearly state that TUOS charges should only be levied at times of high network utilisation and should not impede efficient investment. In our view, those rules are not currently being applied, which is resulting in inefficient outcomes.

Our proposed solution

We recommend the AER addresses this issue by updating and enforcing its TNSP Pricing Methodology Guidelines so that all load (including flexible scheduled load) is charged more cost-reflective TUOS (in line with NER 6A.23.4 and 6A.25.2).

Regardless of whether the AER agrees with our arguments relating to flexible scheduled load, we believe the guidelines need updating. For example, they reference NER clauses that have been deleted (e.g. 6A.23.4(j)).[9]

We recommend the AER reviews the Pricing Methodology Guidelines as a matter of priority. Our rationale is that the review process itself may be lengthy, and implementation may need to be aligned with each TNSP's 5 -yearly regulatory reset. To reduce inefficient outcomes for flexible load in the interim, it is crucial to also update the Cost Allocation Guidelines in the short term, as per our recommendations earlier in this submission.

If the AER chooses not to review the Pricing Methodology Guidelines, we recommend it re-evaluates TNSPs' pricing methodologies and pricing schedules using the current guidelines, but paying greater attention to NER 6A.23.4 and 6A.25.2.

Over the longer term, we believe our suggestions for both prescribed and negotiated transmission services should be enduring, because they address slightly different issues.

Conclusion

Shell Energy thanks the AER for the opportunity to provide feedback on the proposed NTSC for Victoria. This submission recommends that the AER makes an addition to the NTSC, and urgently reviews the Cost Allocation Guidelines. Our intent is to better enable scheduled load willing and able to be interrupted to negotiate a fair price, terms and conditions when seeking a negotiated transmission service.

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[8] In our view, AEMO (as Victoria's TNSP) is the closest to complying with 6A.23.4 and 6A.25.2, with locational charges based on actual demand between 11am and 7pm on the 10 highest-peak days over a year. However, this is still relatively blunt (e.g. because it does not reflect local network congestion, and because the 11am starting point seems unjustified). Based on our assessment of TNSP pricing schedules, no other TNSP's locational charges include congestion-specific time-of-use price signals required to comply with 6A.23.4 and 6A.25.2.

[9] 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

We also recommend that the AER reviews and updates the Pricing Methodology Guidelines, so that TUOS charges for prescribed transmission services are more cost-reflective, as outlined in the NER.

If you would like to discuss this submission further, please contact [redacted], Policy Adviser at [redacted].

Yours sincerely

Libby Hawker
GM Regulatory Affairs & Compliance
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