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Iberdrola Australia submission to Integrating Energy Storage Draft Determination

Submitted to AEMC by website

1. Overview

Iberdrola Australia would like to thank AEMO for preparing a high-quality, forward-looking rule change proposal that will prepare the NEM for a range of emerging business models and higher levels of low-cost renewable generation and storage.

However, we are concerned that the AEMC has used this rule change to dramatically change (for the worse) the investment case for energy storage in Australia by imposing additional costs on storage. It will have material impacts on consumers that are not consistent with the NEO. The AEMC's proposition is contrary to AEMO's advice, and risks overshadowing what was otherwise an important and well considered rule change for the NEM.

Furthermore, increasing the cost of new firming technologies will delay the development of more flexible firm capacity potentially threatening reliability outcomes, and will delay emissions reduction in the NEM. We estimate that TUOS charges could more than double the cost of a near-term battery, despite no additional TNSP costs being incurred. Batteries act to reduce peak demand, thereby reducing costs and prices for consumers. Combined with the AEMC's focus on locational marginal pricing (COGATI) and its reincarnation as the "Congestion Management Model" (a costly and unnecessary tax on new renewable generation), it is increasingly clear that the AEMC would benefit from governments clarifying that the NEO should explicitly consider climate change mitigation and adaptation risks.

2. TUOS and DUOS charging

Iberdrola Australia does not support the draft decision to require energy storage systems to pay transmission use of system (TUOS) charges by default. This will increase cost and complexity to valuable new technologies, which will increase costs to consumer and be inconsistent with the NEO.

Currently, energy storage systems, like most generators, pay for the necessary infrastructure to connect to the grid, including transmission lines, substations, etc.

That is, they do pay for the network augmentation required by their new investment. However, batteries and pumped hydro units do not pay additional TUOS charges unless they seek firm access (and the other protections provided to consumers).

There is a fundamental difference between an end-consumer of electrons, who typically require firm access and other protections, from an energy storage system that simply shifts supply from less valuable to more valuable times of the day or otherwise provides valuable network services (cFCAS, rFCAS, FFR, PFR, and in the near future system strength and inertia). End consumers have the right to draw load at (virtually) all times, and the TNSP has the obligation to build necessary transmission to facilitate this.

AEMO's advice was to clarify that storage does not have to pay for TUOS, as has been the case to date. It is not clear why the AEMC has ignored this recommendation. We disagree with the AEMC's comment that this is "not a major change" to the Rules. Entrenching a default position of storage paying for storage will increase complexity for both TNSPs and developers, with asymmetric negotiating powers.

Charging storage TUOS would significantly increase overall costs to consumers by deferring new storage and inflating wholesale energy prices, above and beyond any recovered TUOS charges (due to the uniform clearing price nature of the NEM). This will increase producer surplus for the incumbent generators and consequently reduce consumer surplus. TNSPs may also be required to build network infrastructure that is not required. This change is therefore not consistent with the NEO.

These issues would be further exacerbated if storage was also charged a connection fee in a REZ – effectively, it would be charged twice for the same transmission infrastructure.

Exempting storage from TUOS does not create a cross subsidy

We consider it is highly unlikely for a battery or pumped hydro project to *increase* network costs, beyond whatever shallow connection costs are required (which would already be paid for by the storage project). That is, adding storage to the network will generally allow for more efficient use of that network, thereby reducing overall costs and prices.

Storage typically only consumes energy during periods when there is excess supply (including behind local constraints) or where it is least-cost to consumers for the storage to deliver network or frequency control service. Storage will also increasingly be embedded in the network (both at the transmission and distribution level), such that its generation can help reduce total network requirements as well.

We are not aware of any instances where deep connection charges have been incurred by consumers due to new storage. Connection agreements for batteries typically (and appropriately) treat batteries as a generator not a market customer (where consumer protections and firmness guarantees would normally come in). They may also include clauses that explicitly do not provide any guarantee of connection to the network – something that consumer loads would be unlikely to accept.

Therefore, there is no first principles reason why storage (a generation technology) should pay as if it were a market customer. In general, no further regulated transmission investment would be required due to the storage load connecting, so there will be no costs imposed on consumers. In fact, by smoothing generation and load, storage may indeed improve load factors and reduce transmission costs. As noted above, trying to recover more of the existing TUOS charges from storage will simply increase overall electricity prices.

Worked example of increased costs

As a specific example, published TUOS charges at Mt Gambier 33kV (for example) are:

- $1861/day fixed, plus
- $80.725/MW/Day Locational, plus
- Lower of $98.458/MW/day and $12.21/MWh, plus
- Lower of $34.626/MW/day and $4.294/MWh

For a 50 MW, 2-hour battery, charging for 2/0.9 = 2.2 hours of the day (given charging efficiencies), this would equate to approximately $3m per year in TUOS charges. Over its 20 year life at a 6% WACC, that would be an additional $36m in lifetime NPV costs, or $716/kW. (This example ignores any change in stored energy capacity over time, or front- or back-loading of warranted cycles.)

This would *double* the capex for a new battery in 2024-25, based on AEMO's 2021 ISP assumptions (~$700-800/kW), and be even more impactful as battery costs continue to fall.

Reduces efficiency of the grid

Based on a typical tariff, TUOS would impose a *short-run* cost on energy storage of ~$10/MWh when charging. This would create inefficiencies – storage would need to recover an addition $10/MWh (plus charging losses) through arbitrage or other services. This will further increase energy costs in the NEM.

Challenges with using the negotiated connection framework

The AEMC have suggested using the negotiated connection framework. This framework requires the price being set at the prescribed charge minus any avoided costs (for the lower level of service). This requires connecting parties to demonstrate an avoided cost for the TNSP in order to deviate from the prescribed service.

The negotiated connection framework will therefore be incredibly complex for every individual battery to negotiate, risks further connection delays of valuable resources, and will cause differences between states.

Network businesses are also increasingly involved in investment in their own batteries. This will create real or perceived risks of favourable treatments to their own assets, leading to less efficient overall outcomes.

Alternative approaches

There are several potential criteria which could be used to determine whether an IRP was liable for TUOS, either alone or in combination. We support the Clean Energy Council's submission to this rule change. Some specific options include:

- A technology restriction could be used such that an IRP consisting only of generator or energy storage resources would not be liable for TUOS. That is, storage would be treated as a "generator" for the purpose of TUOS recovery. Any load that consumes energy purely for the purpose of later returning that energy to the grid (from that facility) would be exempt.
- A "net energy balance" criteria could be used for a resource where total gross load at the connection point is no more than, say, 125% of the total gross generation (i.e., consistent with the efficiency of a typical PHES or battery system).
- The application of TUOS could be updated in the Rules to consider the end-use of electricity. Although this would be complex, this would allow for further technologies to be exempt from storage.
- A broader reform could consider setting starting point for all negotiated TUOS charges to $0 for *scheduled* loads. Resources seeking higher levels of firmness, or with demonstrated impacts on the grid (resulting in higher overall costs), could then pay higher charges.

We note that much of the behind the meter storage will not pay TUOS/DUOS. This is on the basis that it is primarily charging off embedded generation (thereby not charging from the grid) *and* is primarily *offsetting* local load when discharging (thereby *avoiding* TUOS/DUOS charges that would otherwise have been paid.

DUOS

Our comments are primarily on TUOS. However, batteries are also delivering valuable services in the distribution network.

We acknowledge that distribution networks are more complex than transmission networks, with the possibility of both generation and load being charged and potentially harder to separate. As with the transmission network, we expect that batteries are strictly a net positive for the distribution system that reduces overall network costs.

If DUOS were to be charged to storage, it should involve a time or demand based window rather than a flat maximum demand that encourages market proponents to charge their energy storage from the grid that aligns with when the distribution network benefits from additional load (via reduced or even negative DUOS – i.e., payments to charge when it reduces congestion). For example, the "solar sponge" tariff in South Australia could be expanded.

Other technologies

We also recognise there is some level of complexity; for example, a hydrogen electrolyser that produces hydrogen for use in a gas turbine might also be theoretically considered as energy storage. However, an appropriate criteria would be that energy is being stored solely for the purpose of energy production for the same facility, and exclude the production of intermediate fuels. These cases could be appropriately negotiated with the TNSP – particularly if the default negotiating position was one of no additional cost.

While the AEMC's goal of technology neutrality is generally positive, economic purism should not interfere with efficient outcomes. As such, edge cases should not cause the AEMC to block the uptake of valuable resources in the short-term.

Locational signals

A TUOS exemption will not weaken locational signals for new storage.

Generators are already acutely aware of the transmission constraints and Marginal Loss Factors, and these signals are already transparent and effective in the market. As storage will not drive the need for new capacity, TUOS does not provide a relevant locational signal.

We note also that access charging, such as COGATI, will not resolve these issues. COGATI (including its rebranding as the Congestion Management Model (CMM)) is a form of locational marginal pricing, which converts a volume (congestion) signal into a price signal.

Some level of transmission congestion is efficient, but there is no obvious linkage between congestion (or lack thereof) and whether a battery should be charged TUOS. E.g., even if there is congestion, that doesn't mean that a battery is a bad location. Conversely, if there *isn't* local congestion, that doesn't mean that a battery charging is "bad" (and should be penalised by DUOS charges).

The AEMC has suggested that COGATI will create a locational signal. This could only be efficient if it applies to both loads (scheduled and non-scheduled) and generators equally. This would have significant ramifications for consumers.

Historical context is important

It is worth considering the role of storage in improving load factors and reducing transmission and distribution costs. Much of the increase in DUOS in the early 2010s was driven by higher costs to meet increasing peak demand and lower throughput due to energy efficiency. This resulted in increased unit costs given the continued use of 'average cost' throughput tariffs.

Storage has the potential to significantly improve load profiles and absorb the proliferation of new VRE in the system. Given its potential to improve load profiles and reduce overall system costs, it is counterproductive to even consider increasing barriers to storage adoption.

3. New Integrated Resource Provider

We support the proposed introduction of a new Integrated Resource Provider category.

The AEMC's draft determination presents an effective solution that allows for a broad range of emerging business models, including AC and DC coupled hybrid units and batteries used for behind the meter smoothing.

In particular, we support the retention of distinct semi-scheduled and scheduled units behind the connection point (in the relevant models).

Storage registering as a single DUID (Integrated Resource Unit) with 20 bid bands (10 in each direction) seems to be a net positive; there will be implementation costs, but it will also reduce the complexity of having two separate but linked DUIDs.

Generator performance standards (GPS)

We support the AEMC's draft determination that, if existing storage is required to move to the new registration category, there should be no fees. However, we further recommend that this should be a purely "mechanical" transition – that is, there is no risk of the storage GPS being reopened (or requirement for further studies). Reopening would involve significant costs and risks to businesses, and given that there will be no *physical* change to the system of a new registration category, revisiting GPS needs to be avoided. If this is not possible, then existing storage registrations should be grandfathered (which is not a preferred solution).

Further clarification is required on how GPS would be assessed. The draft determination proposes that the GPS applies to the individual unit, but is assessed at the connection point. This concept is counter to the concept of demonstrating compliance with GPS. In this case, a standard would be set at a different place electrically than compliance would be measured. It would not be possible to separate the contribution of the different generating units at the connection point, hence compliance could not be determined. It is preferred that a combined GPS should be proposed at the Connection Point. This would allow performance in one part of a plant to offset that of another, making the project more economically efficient without affecting technical performance at the Connection Point. Such examples may include the inclusion of a single statcom or syncon which may be used to support all of the assets connected, rather than requiring each asset to have its own (which would be required if there were individual GPS). This would also allow technology such as grid forming inverters to provide services to other assets behind the connection point.

Dispatch conformance

Iberdrola Australia supports an aggregate dispatch cap – this will increase efficiency and reduce reliance on ancillary services. However, further clarity over how dispatch conformance of storage and intermittent units behind an IRP is required to provide both investors and the market operator with certainty.

Say that a 100 MW wind farm and a 50 MW battery were in a hybrid setup, registered as a semi-scheduled and scheduled unit, respectively. Iberdrola Australia understands that the compliance of these units with dispatch instructions will be assessed at as a whole[1].

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[1] "conformance with dispatch would be assessed as a whole, subject to AEMO's Power system operating procedure", Integrating Energy Storage – Overview and QandA of Draft Determination, AEMC

- If the wind farm received a 50 MW dispatch cap, and the battery a 50 MW dispatch target, but the actual available wind resource was 60 MW, would the wind farm be allowed to generate more than its 50 MW cap (and therefore save battery energy for a more valuable future period)? Our view is that this is efficient if the dispatch cap reflects a bid price that was cleared by AEMO (e.g., a wind farm bidding above zero).
- If a wind farm received a dispatch cap of zero, would the units be compliant if the wind farm still generated but all energy was consumed by the battery?

Our view is that these are both efficient outcomes that deliver benefits to consumers. However, this may depend on the source of the dispatch cap. For example:

- cleared bids (economic curtailment) – unlikely to be an issue
- thermal constraints – no impact on flows outside of the IRP, so unlikely to be an issue
- system security constraints (e.g., system strength limits) – potential issue

4. Recovery of non-energy costs

Iberdrola Australia supports the proposed framework on non-energy cost recovery, where load or generation (at the NMI level) will be charged its appropriate costs, regardless of the registration category. This addresses the fundamental issues we have raised in Iberdrola Australia's rule change[2], where inequitable cost recovery mechanisms are imposing costs on subsets of consumers with the risk of very high costs during extreme events.

In the medium-term, there may still be scope for a broader review of non-energy cost recovery mechanisms, particularly if more behind-the-meter generation sources are developed, to ensure that no groups are being unfairly treated.

[2] https://www.aemc.gov.au/rule-changes/settlement-under-low-operational-demand