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Mr Rajat Sarawat
Executive Director, Energy Markets
Economic Regulation Authority
Level 4, Albert Facey House
469 Wellington St
Perth WA 6000

Submitted online

Dear Mr Sarawat:

Submission to Triennial Review of the Effectiveness of the Wholesale Electricity Market 2022 - Discussion Paper

EnerCloud Consulting (EnerCloud) welcomes the opportunity to make a submission to the ERA's discussion paper on the Triennial Review of the Effectiveness of the Wholesale Electricity Market 2022 published on 29 July 2022. The commentary in this submission seeks to provide input to two of the specific questions posed by the ERA:

- Question 1 (Discussion Paper p.26): What other investment support mechanisms might be needed to support investment in large-scale renewable generation and battery storage?
- Question 3 (Discussion Paper p.29): What benefits would locational marginal pricing bring to the WEM and how could the costs of locational marginal pricing – uncertainty and price volatility – be managed?

EnerCloud is an energy sector consultancy that brings together a unique blend of expertise in energy markets, power systems, digital transformation, and software development to deliver bespoke end-to-end solutions. The company was founded in Western Australia by specialists with over 14 years' experience in the Wholesale Electricity Market (WEM) and other jurisdictions.

If you have any further questions or would like to discuss any aspect of this submission, please don't hesitate to contact me.

Yours faithfully

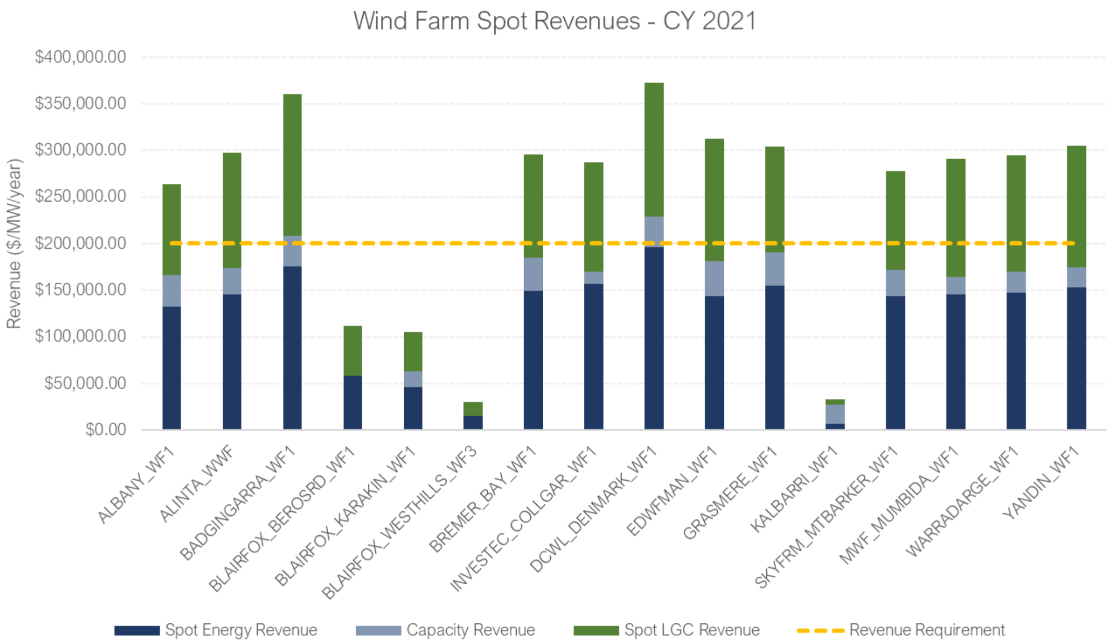
[redacted]

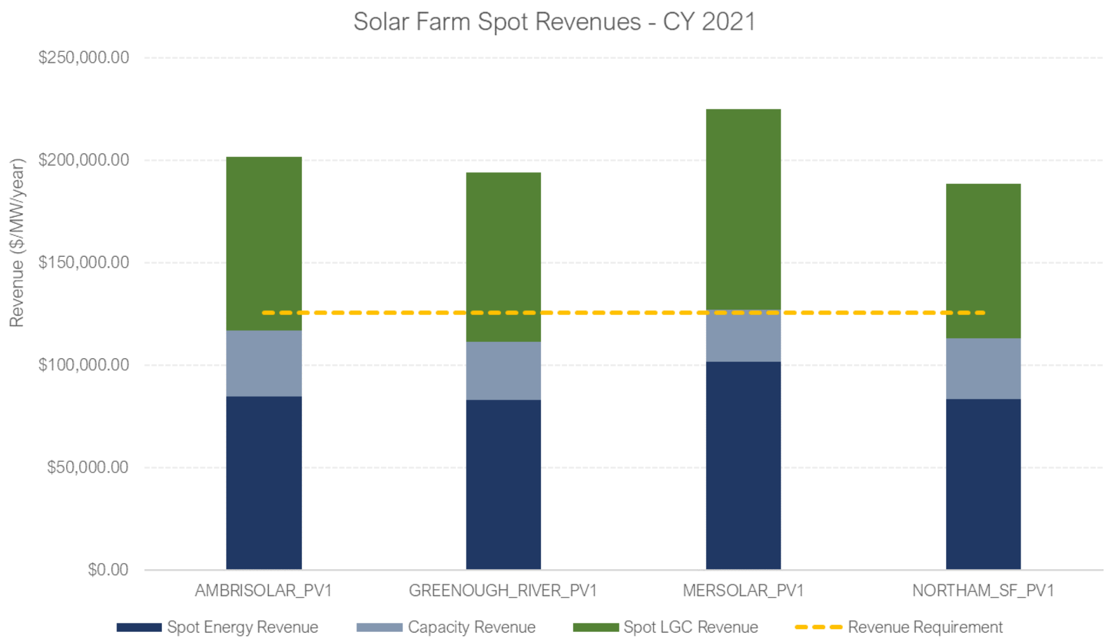
Arthur Panggabean
Managing Director
EnerCloud Consulting

Question 1. Investment support for large-scale variable renewable energy (VRE) and battery storage

Spot revenue sufficiency for large-scale variable renewable energy facilities is a pre-existing issue in the WEM that, as the ERA and consultant analyses indicate, will only worsen with time. Currently, there are only a few large-scale wind and solar farms that would meet their indicative revenue requirements from spot energy revenue and capacity credits alone (if operating in a pure merchant capacity).

For example, merchant spot revenues for wind and solar farms over calendar year 2021 are shown in the following figures:





As can be observed from the spot revenues in 2021, the majority of wind and solar farms (if merchant) are only profitable because of large-scale generation certificates (LGCs). However, as noted in the discussion paper, there is uncertainty regarding what will happen to this revenue stream after the large-scale Renewable Energy Target (LRET) scheme ends in 2030.

Aside from the uncertainty in LGCs, there are other reasons why revenue sufficiency will likely be a challenge for VRE without additional investment support or changes to market rules, including:

- The tendency for higher penetration of VRE to suppress energy spot prices (because of their zero marginal costs),
- Increasing economic (out-of-merit) curtailment of VRE commensurate with higher VRE penetration, leading to a reduction in VRE capacity factors, and
- Uncertainty in the depth of the market for Power Purchase Agreements (PPAs). There will likely only be so many offtakers for VRE generation at prices that would guarantee capital return.

The discussion paper suggests changes to the Reserve Capacity Mechanism (RCM) to incentivise VRE investment by more efficiently valuing the contribution of VRE to resource adequacy, for example by introducing a flexible capacity product. However, it is not obvious to conclude that VRE can credibly contribute enough to resource adequacy and flexibility to justify much higher capacity payments, unless there is a view that VRE firming or maintaining VRE headroom is desired and should be incentivised.

The following mechanisms for supporting VRE revenue sufficiency could also be considered:

- A jurisdictional SWIS RET that guarantees continuation of the federal LRET scheme should it not be continued after 2030.
- Changes to balancing market rules to allow facilities to offer in at long-run marginal cost (rather than short-run marginal cost).
- Allowance for scarcity pricing in the market, either through an increase in the market offer cap (which may be incompatible with the RCM) or through an alternative mechanism such as an operating reserve demand curve with prices that increase as reserves become tighter (e.g. as used in several US electricity markets such as PJM, MISO and ERCOT).

Revenue sufficiency for battery energy storage systems (BESS) is more complicated as SRMC offers can include opportunity costs (reflecting the value of stored energy). This is difficult to capture in most market models as a BESS is usually modelled as a price-taker that engages in energy price arbitrage with no impact on the balancing price. Moreover, most market models don't include negative prices so the cheapest price that a BESS can charge at is zero. So the real picture that may emerge from BESS energy market operations may not be as dire as predicted in the market models, although the concerns around revenue uncertainty from energy arbitrage / time-shifting are still valid.

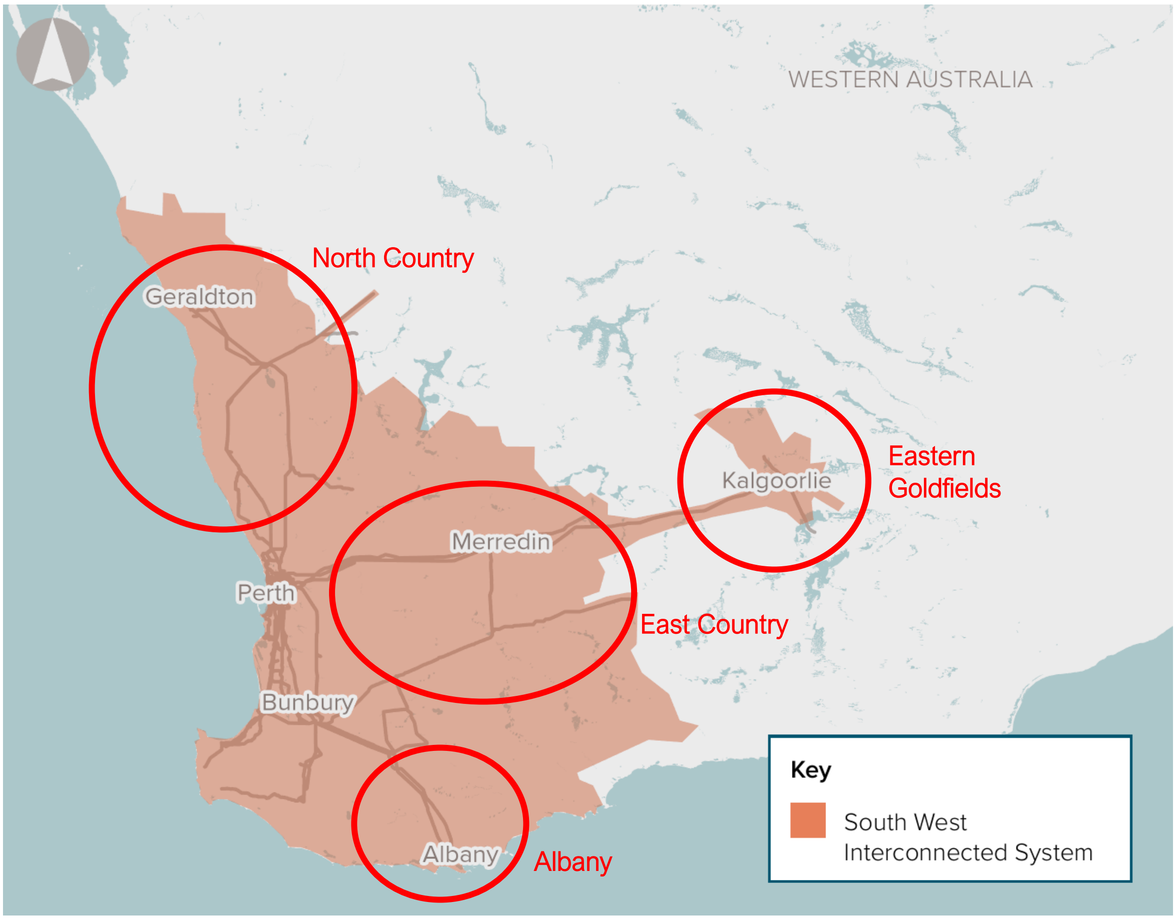
In addition to the measures suggested in the discussion paper for incentivising BESS, there are also non-market value streams that BESS can unlock. For example, a BESS can potentially be contracted by Western Power as part of a non-network solution. There are already examples of BESS being selected as a non-network solution in the National Electricity Market (NEM), e.g. Transgrid's recent North West Slopes and Bathurst, Orange and Parkes area projects.

Question 3. Locational marginal pricing in the SWIS

While theoretically beneficial, we believe the opportunity to bring in locational marginal pricing (LMP) into the WEM has already passed. WEM Reform has committed to delivering a single node gross pool market design and AEMO is already in the middle of developing the new dispatch engine, as well as features required to support the new market (e.g. developing constraints, bid submission portal, settlements, etc). To change tack now would be impractical and would almost certainly delay new market start, and to introduce it later would introduce significant implementation cost to the market and would be disruptive to the market.

The consultant analysis (Figure 22 of Appendix 7) indicates that nodal prices are broadly grouped by zones, which reflect the relative distribution of generation and load, as well as the topological characteristics of the network. For example, the generation-rich areas of Muja and Kwinana have the lowest volume-weighted average nodal prices ($40-$60/MWh), while the largely load-rich areas in the greater Perth metro area have nodal prices in the $80-$100/MWh range. Only the weak and radially connected North Country, East Country and Eastern Goldfields regions exhibit uniformly high nodal prices (>$140/MWh).

Rather than implying a "*thinly meshed network […] prone to congestion"* as the consultant report suggests is characteristic of the SWIS, this distribution of nodal prices is more indicative of a network with a large hub (comprising the Greater Perth metro, Bunbury and Muja regions) that is generally well meshed and uncongested, but with weakly connected "spokes" (like North Country, Albany, East Country and the Eastern Goldfields regions).



Source: Infrastructure Australia

The indicative nodal prices only reinforce what is already known about the SWIS, i.e. that prices would be high in the “spokes” of the network and relatively flat elsewhere. The introduction of LMPs could also disadvantage the customers in these high-priced areas (particularly load centres such as Geraldton, Kalgoorlie-Boulder and Albany).