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To: AEMC
Reference: EPR0076
Submitted via website

Re: Response to **AEMC Investigation into system strength frameworks in the NEM**

Infigen Energy (Infigen) welcomes the opportunity to make a submission. Infigen delivers reliable energy to customers through a portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, including both vertical integrated assets and PPAs. Infigen also owns and operates a portfolio of firming capacity, including a 123 MW open cycle gas turbine in NSW, a 25 MW / 52 MWh battery in SA, and will soon take ownership of 120 MW of dual fuel peaking capacity in SA. Our development pipeline has projects at differing stages of development covering wind, solar and batteries and we are also exploring further opportunities to purchase energy through capital light PPAs. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

In our view, the AEMC has prepared an excellent summary of the emerging challenges in maintaining sufficient system strength for the secure (and affordable) operation of the grid.

In particular, the "do no harm" framework has failed to deliver effective outcomes, and resulted in significant costs to the energy sector. The AEMC has correctly identified the challenges of modelling studies, reactive rather than proactive procurement, asymmetric information and capabilities of participants vs AEMO, and the risk of unexpected new obligations emerging late in the development process. We are also concerned that the installation of a significant number of small, site-specific synchronous condensors will further increase the complexity of future connections.

In our view, system strength is ultimately best described as a network service: it is locational, requires coordination between multiple projects, and requires sophisticated modelling that is not generally available to participants. Like transmission, it is an essential service, and is a fundamental requirement for managing the transition to a clean energy future.

AEMC has proposed four broad options for procuring system strength, which Infigen has considered below.

Option 4 – Access Standard

Under this model, participants would be obligated to ensure they could operate stably in a low system strength environment, such as maintaining continuous uninterrupted operation down to an short-circuit current ratio (SCR) of 3.0.

While there may be merit in standards reflecting best practice (and therefore future-proofing the system), it is not clear that tighter standards on new generation will reduce overall system costs given that the network must, in the medium-term, support the incumbent fleet. There is a risk that this option will simply push additional costs onto new entrants, driving up entry costs and therefore wholesale prices, without delivering benefits to consumers.

It is also clear that modelling and understanding in this space is evolving quickly, with system “strength” being more than simply SCR. Appropriate standards (balancing costs and benefits) may therefore be difficult to define.

Infigen therefore does not support this option at this time, but it may be appropriate to revisit standards in 2-3 years’ time.

Option 3 – Mandatory Service Provision

Mandatory requirements do not reflect the “system service” nature of system strength, will increase the cost of new entrant technologies, and would not address concerns of system stability from having many distributed synchronous condensors. Infigen does not support this option.

Option 2 – Decentralised approach

Organised spot markets are valuable tools for delivering efficient outcomes, but come with significant overheads and are not appropriate for illiquid products (e.g., highly locational system strength services with limited providers). We expect the total cost of system strength services will be low compared to energy costs, and therefore may not warrant market approaches.

This model also assumes that any solution for system strength is somewhat nodal – e.g., installing syncons or synchronous generators at particular locations. The treatment of network solutions in this model would be complex.

The South Australian experience is also that procuring system strength from thermal generators comes at a significant premium to simply procuring synchronous condensors – a service best undertaken by the TNSP. Therefore, co-optimising energy and system strength services in the future may of limited marginal value.

Additionally, while markets could be used to “top up” system strength above a minimum level, we expect that in most cases, once sufficient resources have been procured to meet the “worst” periods, these resources can be applied at relatively low-cost in other periods. For example, transmission upgrades, synchronous condensors, and (to some extent) grid forming batteries will all have relatively low running costs.

In our view, while there should be opportunities to procure centralised services through competitive schemes (e.g., competitive tenders), a decentralised approach to procuring services does not seem feasible at this time.

Option 1 – Centrally coordinated

Under this model, a central procurer would procure sufficient system strength for the future operation of the grid, building on forecasts such as AEMO's Integrated System Plan.

In our view, this is likely the only way that system strength can be efficiently procured in the NEM once *all* costs and risks are taken into consideration. While central planning has the risk of "picking winners", we believe these problems can be addressed.

We have provided further commentary below.

Managing uncertainty

We note that "forecasting is difficult – especially of the future". For example, AEMO's ESOO did not consider the *possibility* of the closure of Northern Power Station in May 2016 in the 2014 ESOO[1], or the *possibility* of the closure of Hazelwood Power Station in March 2017 in the 2016 ESOO, despite both being the oldest coal power stations in their regions[2].

Without sufficient system strength, the unexpected closure of additional future units could jeopardise both existing units *and* delay new supply. Therefore, while "just in time" provision might be the most economically pure procurement, we expect that a least-cost outcome will involve ensuring that system strength is robust under a range of scenarios.

Providing more certainty of coal closure dates may improve planning efficiency and reduce costs. For example, the three-year closure notice period requirement could be a binding commitment (i.e., projects are not permitted to defer closure, but could

[1] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2014-NEM-ESOO

[2] For energy, market participants have strong incentives to maintain additional reserves in the system (e.g., portfolios that contract to N-1 units) to manage similar unexpected events. Infigen has also proposed that a further Operating Reserves framework be introduced to further mitigate these risks.

transition into the RERT if required), or the Grattan Institute has proposed a scheme where nominated closure dates would come with a financial penalty if breached[3].

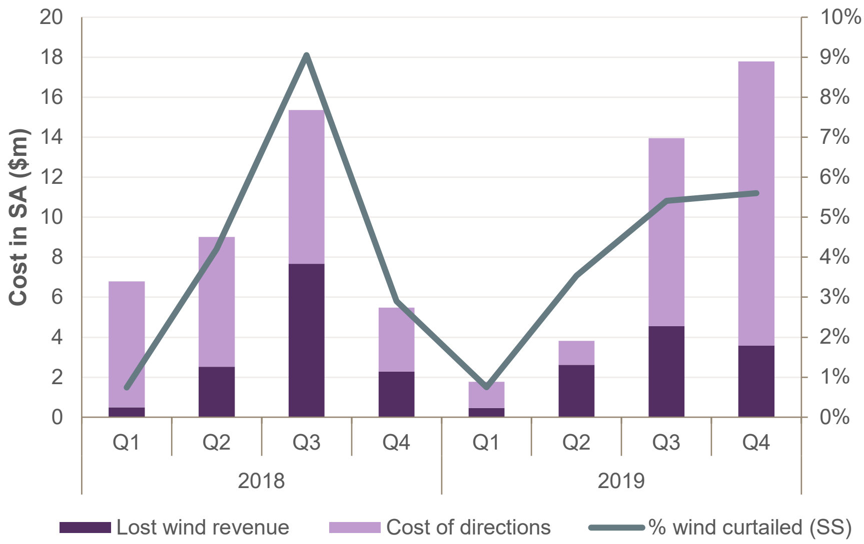
There are asymmetric risks with over- and under-procurement

We note that all procurement methods risk either under- and over-procurement. However, the costs and benefits of these risks are asymmetric. Insufficient system strength will result in project delays and/or the curtailment of resources, which will ultimately result in higher costs to consumers through both higher project hurdle rates (in the long-run) and use of more expensive resources (in the short-run). These directly affect energy costs, which is the primary driver of consumer bills.

In contrast, over-procurement will simply increase the cost of that service, and (as AEMC notes) delivers some value through improved system resilience.

Figure 1 shows the estimated curtailment of wind in South Australia due to the SA system strength constraints[4]. The cost of this curtailment is indicatively calculated by the marginal SA price in each half-hour, plus the SA direction costs. Therefore, the delay in procuring syncons is already costing $11m to $13m per year in lost revenue in South Australia plus $23m to $26m in direction costs, which does not include the cost of project delays and higher future costs.

Figure 1 – Costs of system strength constraints in South Australia



Source: AEMO, Infigen analysis

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[3] https://grattan.edu.au/how-to-clean-up-australias-energy-policy-mess/

[4] To estimate the impact of the system strength constraints specifically, this analysis is restricted to periods of curtailment when SA wind availability exceeds 1000 MW and the SA price is above $0/MWh.

Emerging system strength constraints in other regions will inevitably produce similar costs. For example, curtailment on the Queensland Haughton Solar Farm already has an annualised cost of $1m per year.

System strength should be procured above minimum projected requirements

Therefore, we suggest that TNSPs should be required to procure system strength above the minimum level required in projected scenarios – allowing for unexpected closures and for projects in different locations. This would limit the risk of forecasting errors, and allow TNSPs time to “catch up” (replenish the “buffer”).

System strength forecasting is incorporated into the ISP

In our view, the lack of a clear plan for what is required to maintain system strength (and other essential services) is a significant risk. AEMO should as a priority undertake modelling of options and associated costs for maintaining system strength for the Paris Agreement-aligned Step-Change ISP scenario. This would help define the “size of the pie”, and where issues may emerge over 1-5 years.

Cost recovery

AEMC has considered two cost recovery options – generators paying through connection fees, and consumers through TUoS charges. We agree with the AEMC’s analysis of the options.

Infigen typically supports sharp locational pricing signals, such that commercial decisions take into account as many factors as possible. However, we note the tension between efficiently pricing connection charges and providing appropriate locational signals. For example, the difficulty in setting appropriate locational charges, whether locations *currently* with sufficient system strength should be “free” or whether all locations should reflect the “long-run” cost of maintaining system strength. There are natural parallels with the challenges identified in Optional Firm Access and COGATI with allocating deep connection costs and efficiently pricing transmission access charges – forecasting “long-run incremental costs” is challenging, and assigning those costs to individual participants problematic.

On this basis, further analysis should be done on the feasibility of fixed “system strength” connection charges for broad (electrical) zones in a region, but it may be appropriate in at least the short-term to simply recover costs through TUoS. We also note that coordination with the DNSP may be required at some locations.

Participants should always have the option of undertaking alternative works rather than the TNSP connection charge. This may be managed the same as reactive power where it may be provided on site or contracted (generally with an NSP). In this case though, NSPs should retain the responsibility for configuration/tuning of plant, regardless of location. However, if the challenges of multiple small distributed synchronous condensors (or other similar assets) is to be avoided, there should be a clear negotiation framework with TNSPs and ability for TNSPs to adjust pricing over time as better information is available.

Conclusion

We consider the AEMC has prepared a high-quality report that accurately captures the issues and procurement options.

In summary, in our view:

- AEMO should immediately be tasked with undertaking modelling of the ISP scenarios to identify emerging system strength needs; it is not appropriate that existing projects should be curtailed due to unforeseen system issues.
- TNSP forecasting should use the ISP as a base, but given the forecasting difficulties noted in this submission, TNSPs will likely need to consider additional scenarios (i.e., more in line with TNSP transmission planning scenario analysis).
- TNSPs should procure resources ahead of time to meet expected requirements based on forecasts
- TNSPs should *also* procure/maintain sufficient services to keep system strength at a buffer above the "minimum" levels required by forecasts, under a credible range of near-term scenarios. This buffer will manage forecasting errors (e.g., unexpected coal closures), and avoiding incurring significant system costs
- Further investigation of cost recovery options should be considered.

We look forward to the opportunity to continue to engage with the AEMC. If you would like to discuss this submission, please contact Dr Joel Gilmore (Regulator Affairs Manager) on joel.gilmore@infigenenergy.com or 0411 267 044.

Yours sincerely

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