Submission

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To	AEMO
Reference	NEM settlement under zero and negative regional demand conditions Submitted via email to AEMO.Settlements@aemo.com.au
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Subject Infigen response to AEMO consultation on NEM settlement

Overview:

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 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.

1. AEMO needs to be future focused

AEMO has identified that internal processes are unable to cope with zero or negative operational demand under certain circumstances, and that this could occur within the next 6-12 months, requiring urgent intervention. AEMO has therefore proposed several options that it recommends be implemented as an emergency fix, at a cost of $100,000.

Infigen is very concerned that, despite the possibility of zero operational demand being raised in South Australia since at least 2015[1] and being entirely predictable given environmental policy setting (LRET, SRES, PFiT), AEMO has only now identified a system failure and is requesting urgent fixes without allowing sufficient time to present a measured solution. Given that net zero demand could have conceivably occurred this year, a lack of forward planning has already put consumers (and retailers) at risk of significant disruption.

This is part of a trend of AEMO not undertaking forward planning, including being consistent with Australia's international emission reduction obligations[2]: AEMO continues

[1] Report to COAG Energy Council on Security and Reliability in the Context of Changing Generation Mix (AEMO, September 2015)

[2] The Commonwealth Government has committed Australia to reducing emissions in a manner consistent with limiting anthropogenic climate change to 2 degrees Celsius and with an aspiration to achieving 1.5 degrees Celsius. This should be the central assumption for any future planning of the system.

to underestimate the pace of change and has not modelled credible scenarios (both bookend and central). This results in repeated “surprises” and requests for inefficient urgent changes, and ultimately results inadverse outcomes for consumers and the market. Some examples of insufficient planning include:

- The critical issues associated with low operational demand in South Australia appear to have only been addressed due to a request by the South Australian government[3].
- AEMO does not yet have a plan how it will operate South Australia with the new synchronous condensor units currently being installed. This risks consumers paying for costly interventions *and* new network infrastructure (that was developed on the basis of avoiding these interventions).
- AEMO consistently underestimated the uptake of rooftop solar PV and hence operational demand, which presumably has contributed to the urgency of this proposal. As noted in the consultation paper, negative operational demand was only "expected" in 2024 - but could easily have occurred in 2020. The ESOO forecasts released in August 2020 are already far out of date, with rooftop PV installation rates in all regions except Victoria already far exceeding those projected in the ESOO.
- AEMO’s Central scenario in the 2020 ISP is already out of date following the NSW Electricity Roadmap legislation – but so is the intended bookend Step-Change scenario [Figure ###]. These scenarios are critical for investment in both generation and transmission.
- Rather than planning for operating a future grid, AEMO’s Renewable Integration Study focuses on defining artificial “limits” on renewable generation and leveraging ISP scenarios, rather than developing a proactive plan for managing high penetrations of renewables.
- AEMO did not undertake any modelling of the operation of South Australia without coal generation until *after* the announced closure of Northern power station - leading to the system temporarily operating in an insecure state, and then ultimately significant curtailment, interventions, and costs to consumers. Indeed, AEMO has never modelled coal closures in their year of closure *before* their closure was announced - consistently underestimating the rate of change[4].
- Numerous system strength constraints then emerged around the NEM, leading to average project delays of >9 months, and new constraints or obligations on generators that had already received approvals or even were operational. Rather than completing studies for future needs, AEMO appears focused on short-term fixes[5] that maintain reliance on existing coal power stations[6] - despite these facilities being inconsistent with Australia meeting its international emission reduction commitments.
- While AEMO identified a broadening of frequency performance, AEMO did not define a new operational framework, instead requesting the urgent introduction of a mandatory Primary Frequency Control requirement without any quantitative modelling. The lack of a standard (i.e., the required frequency

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[3] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review

[4] See p6, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_infigen_-_20200813_-_erc0263_erc0290_erc0295_erc0296_erc0300_erc0306_erc0307.pdf

[5] https://www.aemc.gov.au/sites/default/files/documents/aemo_submission_system_strength_investigation_070520.pdf

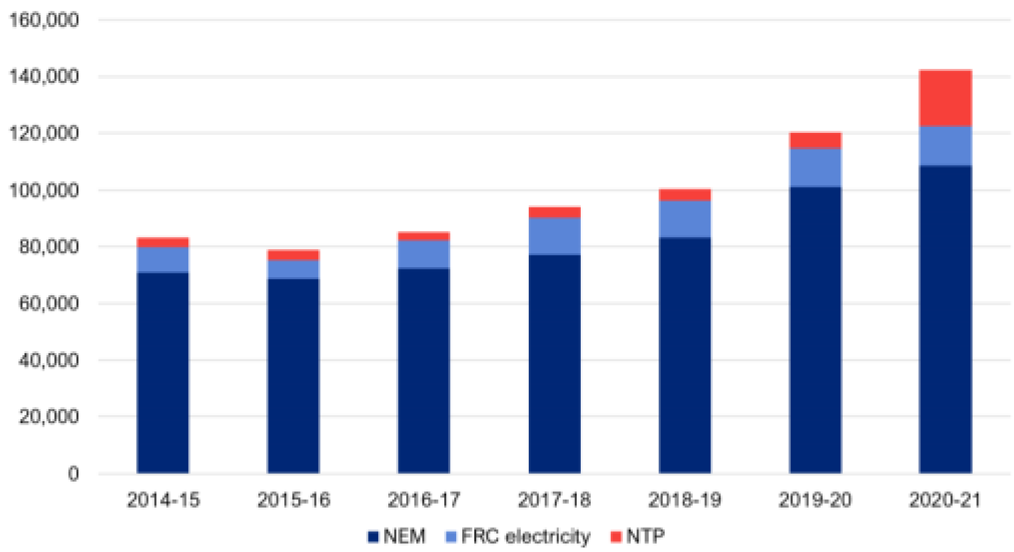
[6] For example, AEMO initially refused to consider emissions targets for the 2020 ISP, and AEMO continues to raise concerns about utilizing existing coal for system strength, effectively deferring AEMO’s need to plan the system in advance. p18, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_aemo_-_20200813_-_erc0263_erc0290_erc0295_erc0296_erc0300_erc0306_erc0307.pdf

distribution for a secure system) means there is no way of modelling or incentivising necessary resources in the future as coal plant closures. AEMO has also used its regulatory powers, and has pursued changes to the NER, to allow it to procure essential services at less than fair value. This creates the very real risk of degraded performance when large thermal plant closes (inevitably ahead of AEMO's forecasts).

1.1 AEMO needs a clear operational plan for the grid that is future focused

These disruptions go to the heart of AEMO's responsibilities as the market and system operator: AEMO's primary responsibility is maintaining power system security, which requires a clear plan for operating the market in both the short- and long-term. Unfortunately, as explained above, AEMO does not seem to be focused on the medium and long-term. This is despite a significant increase in the resources available to AEMO (Figure 1, Figure 2). A continued failure to plan will inevitably lead to last-minute interventions, the development of new rules "on the fly", and material costs to consumers as has been seen in South Australia.

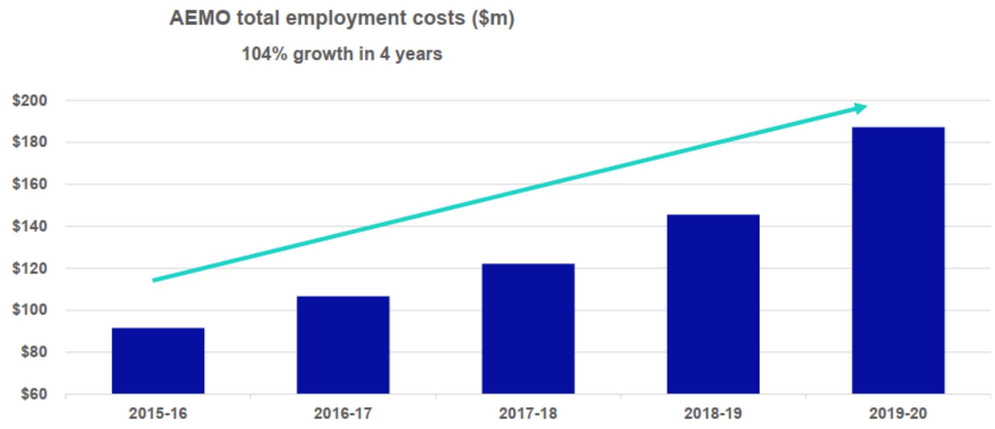
Figure 1 AEMO's budgeted revenue requirement ($'000) for electricity market roles - excluding Vic TNSP, SA planning, and WEM functions[7]



Source: AEMO, budget and fees documents

[7] Note that AEMO's 2019-20 Final Budget and Fees document projected fee increases at the maximum level of 12% pa over three years, which was reduced to 9% for 2020-21. Source: Governance and regulation of market/system operators, CEPA report to AEC and ENA

Figure 2 AEMO employment costs



In contrast, AEMO has spent a disproportionate amount of time on low-priority areas such as advocating for 'big picture' reforms such as ahead markets and capacity markets[8]. This is the AEMC's, and not AEMO's, core responsibility, and appears to be being undertaken at the expense of other priorities.

AEMO's Final Budget and Fees document stated that AEMO would be required to "reduce or cease some activities" as a result of reducing the budget increase to 9% (from 12%) in FY21. Therefore, as AEMO considers its operations over the next year, we believe AEMO needs to focus its resources on ensuring no future *unanticipated* disruptions will occur. In particular, we recommend:

1. AEMO should urgently establish a dedicated *technical operations* team to assess the risks around low operational demand across the NEM, including:
   - power system security;
   - appropriate management of distributed resources;
   - availability of essential system services; and
   - impacts on customers.

   AEMO should be cultivating high performing technical teams with the skills required to tackle novel power system security challenges that will inevitably continue to arise over the coming decade. This is not short-term work, and should not be resourced as such.
2. AEMO needs to assess whether any other market or operational systems are likely to be impacted at zero operational demand (or near-zero demand, as discussed below).
3. AEMO should develop a clear *forward looking* plan for operating a decarbonised power system, including the potential network infrastructure (syncons, grid forming batteries) necessary to operate the system under a range of scenarios. This will also help inform the definition and requirements for System Strength zones if a rule change is made under the TransGrid proposal, and help quantify the benefits and costs of building sufficient resources to manage uncertainty.

[8] AEMO's contributions to the ESB post-2025 reform have similarly been limited to market design suggestions, rather than the necessary technical modelling needed to underpin future decisions.

4. Similarly, AEMO must ensure existing systems and processes can function with 100% renewable generation, rather than waiting for future triggers. Transparent standards and requirements must be communicated to the market.
5. The 2022 ISP must model a true bookend scenario, i.e., 100% renewables by 2030, to ensure that AEMO, industry, and governments are ready if and when the transition occurs earlier than expected.
6. AEMO should establish KPIs that include minimum lead times for identifying and actioning potential market or system failures

2. The issue

AEMO has identified that the current market settlement system will fail when operational demand is zero or negative. In particular, this is because while the costs of the relevant FCAS services are fixed[9], the allocation of costs to a market customer are given by the general formula:

$$\text{Allocated cost} = \text{Service cost} \times \frac{\text{Market Customer's AGE}}{\sum \text{AGE}}$$

where the denominator is effectively the operational demand.

Services such as directions, and local Contingency FCAS requirements are procured on a regional basis. In a situation where some participants have negative AGE, this means that the total regional demand ($\sum AGE$) can be zero, leading to a failure of the equation. This equation (and proportional allocation of costs more generally) implicitly assumes that each term in the equation is positive.

We agree that this must be addressed quickly.

2.1 AEMO must share any relevant analysis

However, while AEMO has focused on this narrow technical aspect of their settlement systems, we are concerned that AEMO has not investigated whether there are other related, but equally urgent, issues.

For example, periods with zero scheduled or semi-scheduled generation seem less likely in the short-term – but would these cause similar failures for the recovery of services such as Raise Contingency? Aside from one footnote noting the narrow scope, AEMO has provided no evidence it has considered these risks.

If AEMO has undertaken analysis of where risks do or not exist, this needs to be transparently communicated to participants immediately.

[9] Assuming the quantity of procured services does not change

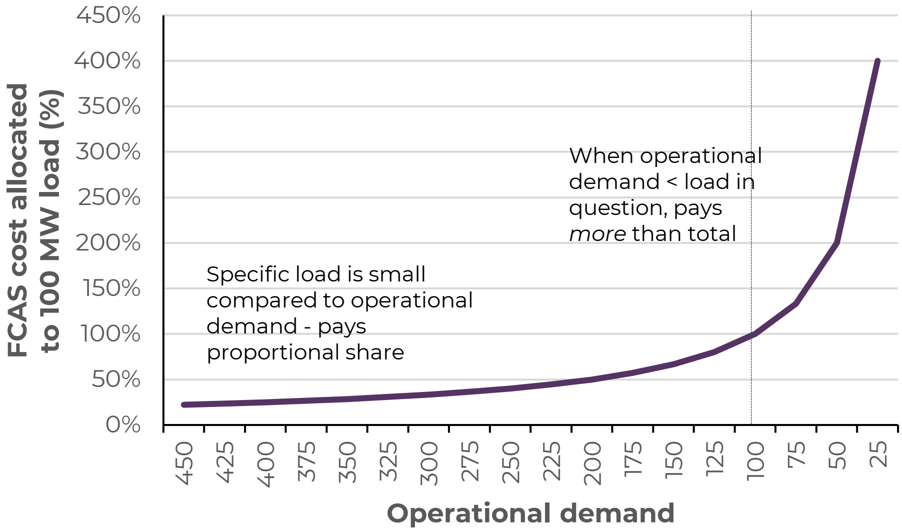
2.2 Risks when operational demand is low but non-zero

More generally, we note that the above equation also effectively fails when the net operational demand is *low* but still positive.

As the operational demand reduces due to solar exports, the remaining loads pay a higher share of the system services. While we acknowledge that allocation of costs is a complex issue, Infigen understands from AEMO that the current system results in NMIs with positive loads effectively *paying* NMIs which are net exporters. (I.e., in the above formula, the sum of all AGEs may be positive (denominator), but one specific AGE may be negative, resulting in a negative cost, i.e., a payment).

Figure 3 shows that as the operational demand decreases, the remaining loads pay a higher share of the costs of the service, despite not contributing to a greater need for the service. However, as the net operational demand approaches (and then goes below) that of a specific load, that load may be required to pay *more* than 100% of the total service costs – with the extra being paid to the net exporting load, despite not contributing to the service (and also not paying for any contribution).

Figure 3 Schematic sensitivity of allocated costs vs operational demand



At the extreme, if operational demand approached AEMO's proposed 1 MW threshold, the current cost allocation to a hypothetical 100 MW customer would approach 100 times the total regional FCAS, NMAS and direction costs at the time[10].

2.3 South Australian case study

This is not merely a theoretical argument; the cost impacts to customers of South Australia *approaching* 1 MW operational demand are likely to be material.

[10] That is, the current procedure would allocated 100 MW / 1 MW = 100 times the cost of the service.

Regional contingency lower FCAS services can be above $100,000 for a single trading interval (TI) in SA. Indeed, since 2017 there have been over 20 TIs where lower contingency costs were over $500,000 in the state. If such a price event were to occur at a time of very low operational demand, resulting in individual customers paying multiple times the total regional costs as outlined above. Infigen believes the impact would be unacceptable.

As a specific example:

- between 6:00 and 7:00 am on 9th November last year, an average of more than 100 MW of each 6 and 60 seconds lower contingency service was enabled in SA. In the 6:30 am TI each of these services settled at over $13,000/MWh, while in the 7:00 am TI they settled at the market price cap (MPC) of $14,700/MWh.
- The total cost of lower contingency services to the region over this hour-long period was $3.4m, with all loads paying a proportional share.
- However, if this scenario was to coincide with a period of low regional demand then as regional demand approached AEMO's proposed 1 MW threshold, the cost to a 100 MW industrial load with no PV would pay up to $340m – 100x the actual cost of the service.
- This would be a ~$340m wealth transfer from remaining loads to net exporters.
- In contrast, the cost of supplying the 100 MW load for one hour at the MPC would have been "just" $1.5m.

This scenario demonstrates that as the operational demand decreases *and* under current settlement systems, the MPC may no longer adequately protect consumers or reflect consumer preferences. Market customers will be exposed to unnecessary (and unrealistic) cost that they may not be able to absorb.

This does not seem consistent with good market design and has other perverse outcomes such as creating an incentive to push demand negative, which may not be good for the market.

3. Infigen response

In our view, the long-term market design intent should be to recover the cost of ancillary services from (where applicable) Market Customers in proportion to their size. The challenge is finding an appropriate proxy for this cost recovery. We note that a load that is exporting embedded generation or is net-zero demand presumably still contributes the same requirement to Regulation services, and may contribute to the need for either Raise or Lower Contingency services (or both). These issues are being considered by AEMC, such as through the Energy Storage Systems Rule Change.

We acknowledge, however, that there is a "mechanical" problem that needs to be addressed urgently. However, we urge caution in proceeding before the issues raised in Section 2 are addressed.

3.1 AEMO options

Infigen provides the following comments on AEMO's proposals:

- Option 1 provides a mechanical solution to the immediate issue (the failure of the settlement systems when demand is zero/negative). The historical load over the previous calendar year will be used as a proxy. As a short-term fix, this has the advantage of being simple to implement.
- Option 2. This option is very similar to Option 1, but using a rolling average. We are unclear why AEMO has identified different advantages and disadvantages compared to Option 1 (e.g., "All active Market Customers would share the cost" is unclear). While a rolling average would be better, the additional complexity in settlement (for both AEMO and participants) makes this less preferred than option 1.
- Option 3. We agree that using an instantaneous figure rather than a longer-term average is less preferred.
- Option 4. We agree that recovering costs equally from all market customers is less preferred.

3.2 Alternative short-term fix

Infigen proposes an alternative option that would defer the zero operational demand problem (allowing time for a more considered discussion of cost allocations), while also addressing the settlement issues that seem to occur around low operational demand.

A key problem seems to be significant negative AGEs in the future. Removing these would defer, but not eliminate, the issues presented above. Infigen therefore proposes that the AGE of a Market Customer could modified to be either:

a) floored at zero, so negative loads are not included in settlement; or

b) treated as the absolute value, so that loads that are net exporters still pay a share of the service.

The settlement equation would then become either:

$$\text{Allocated cost} = \text{Service cost} \times \frac{\max(0, \text{Market Customer's AGE})}{\sum \max(0, \text{AGE})}$$

or

$$\text{Allocated cost} = \text{Service cost} \times \frac{\text{abs}(\text{Market Customer's AGE})}{\sum \text{abs}(\text{AGE})}$$

Both approaches would ensure that costs are allocated fairly between participants, with total costs recovered being limited to the total service cost. The latter option is particularly attractive as it would help ensure loads that are currently exporting continue to pay *some* share of the services they require. It would however create an incentive to target net-zero consumption, which may not be desirable, and it does not preclude the need for more comprehensive discussion of how costs are recovered.

This approach assumes that there will continue to be net loads in the system offset by significant solar exports (negative loads) in other areas. It would not provide a solution if *all* "loads" in a region were negative.

Conclusion:

AEMO has not provided sufficient quantitative analysis to understand the impacts or, in our view, sufficiently reviewed the related issues around *low* but not zero demand. There may be other issues that also need to be addressed urgently, and it would be sensible to address them together.

We recommend AEMO undertake further consultation, and:

- AEMO provide further insight into the causes of the zero operational demand. For example, what percentage of NMIs have zero/negative demand? The appropriate short-term response
- AEMO conduct some case studies of the impact of each of the options on some example customers in South Australia
- AEMO engage immediately with the AEMC and the Reliability Panel to understand the potential implications of any changes, as well as the issues raised by Infigen above around low operational demand.
- AEMO investigates, or publishes previous investigations on, whether there are other critical issues that need to be addressed at the same time.

Infigen recommends AEMO consider the option presented above as a preferred interim solution (or, possibly, complementary – implementing Option 1 as a backstop).

We look forward to the opportunity to continue to engage with the AEMO. 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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