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Dear Mr. Cormack, Dr. Johnston,

Response from EnerNOC to the **Open Energy Networks** consultation paper published by AEMO and Energy Networks Australia, dated 15 June 2018.

EnerNOC is an independent demand response aggregator with experience operating in twelve countries. We work with commercial and industrial energy users to enable dispatchable demand-side flexibility, and offer that flexibility into wholesale capacity, energy, and ancillary services markets, as well as to networks and utilities. Locally, EnerNOC is a market participant in the Wholesale Electricity Market (WEM) and the National Electricity Market (NEM). EnerNOC's regional head office for Asia-Pacific is in Melbourne. In 2017, EnerNOC became part of the Enel Group.

Thank you for the opportunity to contribute to this consultation. Please get in touch if EnerNOC can contribute further – we would be glad to discuss the contents of this response in more detail.

Regards,

[signed]

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Summary

The *Open Energy Networks* consultation paper is an important first step towards charting the NEM's pathway to efficient and secure DER integration. The recent announcement by the AEMC in its *Reliability Frameworks Review* final report are highly complementary to this consultation and the resultant rule changes should provide an opportune vehicle for AEMO and the ENA to advance specific DER-related reforms.

If it is determined that a new platform is required in order to effectively integrate increased quantities of DER, then creating a Single Integrated Platform administered by AEMO would be far superior to multiple platforms administered by each DNSP. However we encourage AEMO to explore whether a new platform is required, or if the desired outcomes can be achieved simply by enhancing NEMDE, and providing more and better information to it.

Finally, we suggest that this consultation would benefit from more detailed discussion of the opportunities and challenges presented by the prevalence of increasing quantities of electric vehicles in the system.

The AEMC's recent decision in its *Reliability Frameworks Review* complements this *Open Energy Networks* consultation, and will pave the way for formal integration of DER into the NEM's wholesale markets.

In its Final Report on its *Reliability Frameworks Review* published 26 July 2018, the AEMC announced its intention to facilitate the introduction of three specific reforms intended to lower barriers to demand side participation in the NEM's wholesale markets, and to formalise the way demand side resources participate in the markets. These announced reforms are highly complementary to the work AEMO and the ENA are undertaking through the course of the *Open Energy Networks* consultation, and should do well to assist in realising the efficient dispatch and management of DER – relative to the status quo.

Specifically, the AEMC has proposed the introduction of a new mechanism that would allow 'active DER' to be aggregated together (regardless of the DER's retail supply arrangements) by a registered third party aggregator[1], and bid into the NEM's wholesale markets for energy and ancillary services on a scheduled basis. In doing so, so-called "Virtual Power Plants (VPP)[2]" would transition from being non-scheduled and invisible to AEMO (and thereby problematic) – to being scheduled and visible to AEMO, interacting with the wholesale market in a similar manner to traditional generators. The introduction of such a new mechanism will represent the single most important framework for

[1] The AEMC has proposed that a new category of market participant be created, called a "Demand Response Service Provider (DRSP)"

[2] To us, the term "VPP" refers to an aggregation of behind-the-meter resources capable of being dispatched and controlled to alter grid-facing demand or generation. A VPP would constitute a single "dispatchable unit" in AEMO's market systems, but would be underpinned by dozens, hundreds, or thousands of behind-the-meter resources. A single VPP might be comprised of multiple technology types in including (non-exhaustively) load curtailment, standby diesel generation, or battery state-of-charge management, and may span multiple consumer size classes – from "large" C&I to "small" residential customers.

formalising active DER and ensuring they integrate into the NEM in a manner that solves problems, rather than exacerbates them.

Page 21 of the consultation paper well describes the system security challenges that could arise from allowing active DER VPPs to continue to operate in a non-scheduled manner. The idea of maintaining headroom on the Heywood interconnector in order to cater for non-scheduled VPP movements is an extreme example of the steps AEMO would have to take unless VPPs dispatch becomes scheduled in some way. Some degree of scheduling is inevitable – we suggest the NEM simply get on with the task of defining a threshold above which a VPP must become scheduled, and begin implementing it. It would seem that the rule changes flowing from the Reliability Frameworks Review will be the ideal vehicle for designing, discussing, and implementing the framework that will facilitate scheduled VPP operation, so we suggest that AEMO and the ENA participate closely in the consultation, and view the rule changes as vehicles for solving or remediating some the issues with DER identified in the *Open Energy Networks* consultation paper.

Such a new framework will inevitably require changes to AEMO's market systems, and are likely to require VPP operators to register each participating NMI (that constitutes the VPP) with AEMO in some way. As these market systems are designed, AEMO should ensure the data-capture process collects (and stores on hand) sufficient information about the location of each NMI in the LV network – in order to address issues raised in the consultation paper.

If a new platform for orchestrating DER is needed - creating one central AEMO-administered platform is much preferable to creating multiple DNSP-administered platforms.

Of the three options presented, the consultation paper's Option 1 (Single Integrated Platform) seems to us far superior to Option 2 (Two Step Tiered Regulated Platforms) and Option 3 (Independent DSO). The amount of duplication and redundancy required to develop and implement options 2 and 3 would be staggering. While implementation of options 2 or 3 would be a boon for software developers and the opex line item on each DNSP's balance sheet, the introduction of multiple unnecessary middlemen in the bid submission and dispatch process would introduce unnecessary cost and complexity for market participants and (by extension) unnecessary costs for consumers.

Figure 10 is particularly bizarre – why would we design a pathway whereby DNSPs, TNSPs, AEMO, and P2P providers all design their own procurement platforms, with the expectation that at some point the various platforms will coalesce into one? Instead, it would be preferable to get on with designing the single "coalesced" platform in the first instance. The single Platform in Option 1 is clearly preferable – and we suggest that the "disadvantages" listed for Option 1[3] aren't really *disadvantages*, but rather *challenges* that are solve-able with increased real-time information and increased funding flowing into AEMO.

Is a new Platform required, or could AEMO instead just enhance NEMDE?

Taking a step back, we encourage AEMO to consider whether a new Platform us required in order to achieve its desired future, or whether NEMDE simply needs more information than it has today. Rather than creating a new platform(s) that operate alongside NEMDE, could we just enhance

[3] P30

existing NEMDE? NEMDE is already a highly transparent, logic-driven dispatch engine. If NEMDE had additional information about demand levels in each specific corner of the LV network, and it had granular bid information from market participants that allowed it to dispatch the system (or even an individual dispatchable unit) at sub-region levels at times – would it achieve the same effect as designing a new Platform(s) that do the same?

Introducing sub-regional dispatch is worthy of investigation, but risks introducing complexity that will hinder VPP integration

One potential solution to accommodate emerging LV network constraints would be to require that a dispatchable VPP be capable of being partially dispatched, based on LV network conditions in specific geographic localities within a NEM region. To do this, NEMDE would need to have enough information to receive an aggregated bid (from the VPP) at the region level, and then deconstruct/disaggregate the bid into its constituent parts if needed, in order to avoid violating LV network constraints. The VPP could bid and be settled in the aggregate at the NEM-region level (as generators do today) but could be dispatched sub-regionally in instances where it is economically efficient to do so, or required in order to maintain system security.

However, introducing sub-region dispatch would represent a major change that would need to be carefully considered, as it would require changes to the ways market participants (including future scheduled VPP operators) formulate bids. Introducing sub-region dispatch risks changing the aggregation "hierarchy" and thus multiplying the complexity and cost for scheduled VPP aggregators. For example, under today's NEM framework an aggregator would simply need to calculate availability and aggregate their customers together in each NEM region - for purposes of formulating firm bid quantities and submitting them to NEMDE. EnerNOC's current participation in the wholesale FCAS markets is a useful illustration of this principle:[4] despite sourcing FCAS from dozens of C&I customer sites distributed around the east coast[5], EnerNOC has registered a single dispatchable unit (VPP) in each of the VIC1, NSW1, and QLD1 NEM regions, and so has just three separate aggregations to manage and formulate bidfiles for. If AEMO were to change the aggregation hierarchy such that aggregators had to submit bidfiles at the say, Region + Transmission Node + Zone Substation level (so that NEMDE could dispatch sub regionally, if it needed to) it would multiply the number of distinct aggregations the aggregator needs to manage and formulate bidfiles for – dramatically increasing the complexity and cost of organising and operating scheduled VPPs. If today's FCAS markets required this kind of discrete bidding, it is unlikely EnerNOC would have chosen to enter the FCAS markets, as the costs and overheads related to managing so many distinct aggregations would render participation uneconomic.

Price responsive resources should be scheduled in some way or otherwise integrated into AEMO's dispatch systems.

While scheduling VPPs is an obvious solution for preventing wild, unscheduled swings in grid-facing demand, the scheduling of behind-the-meter introduces an existential question that will be tricky to address: When will energy users be required to ask for permission in order to consume a particular

[4] EnerNOC bids Contingency Raise FCAS under the relatively new Market Ancillary Service Provider (MASP) framework. EnerNOC has published more detail about how our operation works here.

[5] Each of these individual FCAS sources is registered and approved by AEMO, and AEMO has access to information including the NMI at each EnerNOC customer site.

volume of energy at a particular time? As a starting point for answering that question, we suggest that resources that intend to respond to spot prices (by suddenly injecting energy, or withdrawing demand) be required to participate in the central dispatch process in some way.

Electric vehicles need to be part of the conversation

The consultation paper presents and discusses two categories of behind-the-meter DER: Passive DER (i.e. residential solar) and active DER (i.e. residential batteries and flexible loads). We suggest that the latter category could be usefully differentiated into two distinct categories: Active *Stationary* DER and Active *Mobile* DER.

Mobile demand centres (i.e. EVs) represent an altogether new challenge for network design and system operation, and we suggest that they have the potential too magnify and exacerbate the challenges the consultation paper has described for simple active *stationary* DER. To illustrate this future challenge, one only need consider an example like a sporting event at the MCG, where many hundreds of electric vehicles might periodically converge on a small geographic area and desire to recharge, or an entire neighbourhood of EV drivers returning home at 6pm and desiring to recharge.

We suggest that AEMO and the ENA could highlight some of these future challenges in their next *Open Energy Networks* paper – and we suggest that EV integration should remain front of mind as stakeholders are pondering the design of future market services and market frameworks to accommodate DER.