# Response to Open Energy Networks Consultation Paper

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evoenergy

# Document management

## Version control

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## Approval

| Date | Name | Position | Signature |
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# 1. Overview

## 1.1 About Evoenergy

Evoenergy operates the regulated electricity and gas networks in the Australian Capital Territory. Our electricity distribution network supplies electricity to over 190,000 customers.

The ACT Government has the most ambitious targets for renewable energy deployment and greenhouse gas emissions abatement of any Australian State or Territory Government. The targets are strongly supported by our customers, the ACT community. Evoenergy is supporting the Government and community in reaching these targets by actively transitioning our network to accommodate a higher proportion of renewable energy.

In this environment, Evoenergy is facing a number of new challenges and opportunities. Increasing technical challenges in maintaining the quality and reliability of supply have required us to develop new business processes and IT systems to better monitor and control the network. The adoption of new technology is providing Evoenergy with opportunities to reduce and defer capital expenditure via demand management activities, benefiting our broader customer base. We are also investing in the research and trialling of Distributed Energy Resource (DER) management systems to reduce the time it will take for our customers to realise the full benefits.

## 1.2 Our response to the Open Energy Networks Consultation Paper

This response to AEMO/Energy Networks Australia's Open Energy Network Consultation Paper sets out our experience and views as to the need and preferred approach to DER monitoring and control.

Our response seeks to inform AEMO/Energy Networks Australia of:

- Our expectations for the timing and extent needed for DER monitoring and control;
- The current activities we are already pursuing in readiness for this future need; and
- The priority actions for AEMO and Energy Networks Australia to ensure that, as an industry, we can continue to evolve and refine the preferred approach in a timely manner.

Our response is informed by our first-hand experience of emerging challenges and opportunities associated with DER in our network, as well as by our current ongoing investment, investigations, and trialling of DSO concepts.

We welcome further engagement with both AEMO and Energy Networks Australia in finalising the approach.

# 2. DER in our network

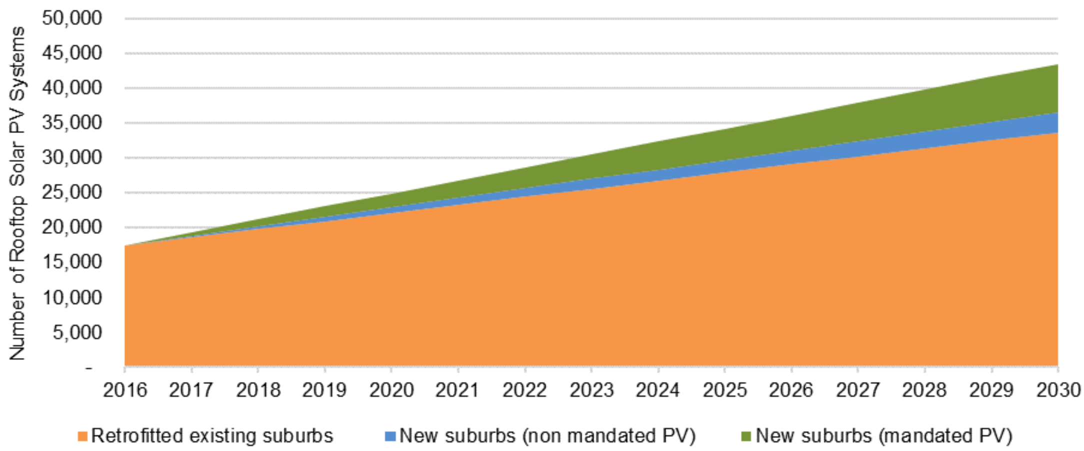
## 2.1 DER trends

Domestic rooftop photovoltaic (PV) generation systems are currently installed on approximately 9.4% of homes in the ACT, varying in size from 1 kW to 10 kW in capacity. There has also been an increase in rooftop PV systems being installed on commercial and community buildings over the last few years. These systems range in size from 30 kW to 200 kW. Currently we have a total of 20,478 small to medium scale solar PV systems with a total installed capacity of 71.7 MW. This is in addition to the large-scale solar farms supplying the territory with a maximum installed capacity of approximately 50 MW.

In the short term, we are expecting significant growth in rooftop solar PV in suburban development corridors, particularly in estate developments that have developer mandated 100% PV penetration. This appears to be the future operating model for all estates within the ACT. It will be undesirable for our customers in these estates, or indeed our broader community, for export constraints to be imposed where the solar PV investment has been made with the expectation of unconstrained export.

We forecast that by 2030, there will be a total of 43,500 solar PV systems with an installed capacity of 128.9 MW. This represents a penetration rate of 21%. As shown in Figure 1, the increase will be driven most significantly by new systems installed in existing suburbs (retrofit) with smaller contributions from new suburbs with mandated and non-mandated PV.

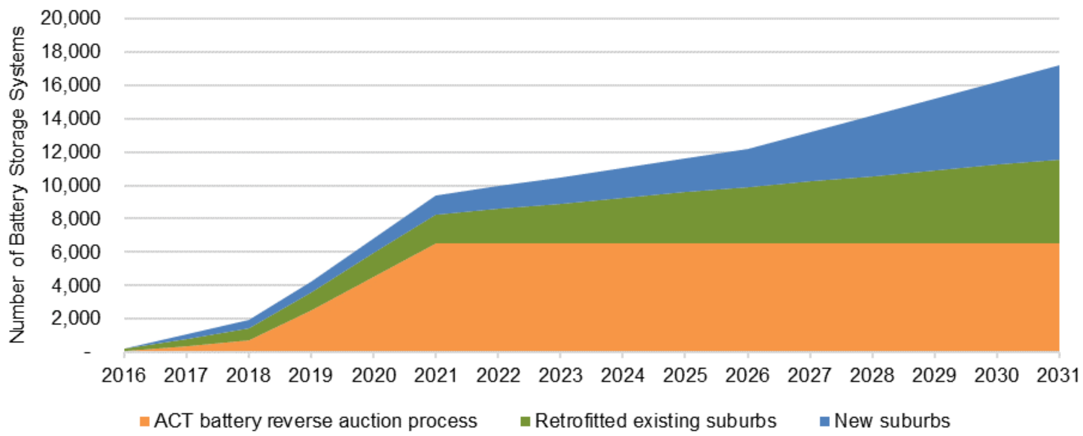
FIGURE 1 – SOLAR PV FORECASTS[1]




[1] Note these forecasts represent our 'conservative' scenario and are based on assumptions of future technology price trajectories, customer preferences, economic and policy settings all of which contain a large degree of uncertainty. The forecasts therefore include a high margin of error.

Battery storage systems are also expected to increase over the period to 2030 such that by 2030 we expect to have approximately 16,200 systems (at a 8% penetration rate) and 193 MWh of storage capacity in our low voltage network.

FIGURE 2 – BATTERY STORAGE SYSTEM FORECASTS




Network constraints caused by a high DER penetration are likely to be confined to specific areas of the low voltage network. As DER capacity in the low voltage network increases, constraints will extend to the medium voltage levels and will eventually be reflected at the zone substation level. It is not forecast that constraint issues caused by DER, nor peer-to-peer DER transactions, will be seen in the transmission level in the short to medium term.

In the short term Evoenergy will face these problems in its suburban development corridors, particularly in estate developments that have mandated 100% PV penetration.

In the long term, the penetration rate of DER is expected to increase progressively in established suburbs although wide-scale impacts in our existing networks are not expected in the short to medium term.

Evoenergy has commenced the transformation progression but it is a difficult learning process requiring time to develop the Operational Technology (OT) systems and demand management response mechanisms to the degree required.

For example,

- Virtual Power Plant trials performed over 2017 and 2018 showed that greater control over battery State of Charge (SOC) and system visibility at the LV edge of the network is required for effective operation of a VPP.
- Real-time optimisation of network load flows and associated data accuracy is required for faster fault location and isolation, particularly in locations where DER penetration is high.
- Real-time updates of dynamic network assets, such as on-load tap changers, through our distribution management system.
- Accurate modelling of energy storage and small scale generation is required for effective planning strategies and requires up to date OT systems to perform.

## 2.2 DER management

### 2.2.1 Existing network

The current level of DER penetration within our network can be managed with minimal impacts to power quality and reliability.

However, since the introduction of the new standard for grid connection of inverter energy systems (AS4777) we have seen an increase in power quality complaints from both load customers and from new solar PV customers tripping off. AS4777 compliant inverters are required to trip on over-voltage. Older, non-compliant inverters do not trip off when the network voltage exceeds the AS4777 threshold. This results in the newer systems being disconnected when the network voltage increases, whilst the older systems remain connected. To date, we have been able to manage these issues through a combination of low cost responses including power quality monitoring and tap changing at transformers.

Unlike other networks with higher solar PV penetration, we do not, at this point in time, propose to adopt any export limits or export controls for low voltage connections via the connections process. We believe that, at least in the short to medium term, we are able to manage solar PV exports, and enable our customers to receive the full value expected for their DER investments.

### 2.2.2 New estates in growth corridors

For our new estates in growth corridors, load flow modelling shows that a 100% penetration rate will significantly increase reverse energy flows to magnitudes greater than the load (consumption) flows. The presence of daily generation cycles in the growth corridors also show the voltage going beyond the higher and lower bounds of the regulated voltage limits and requires multiple tap changes every day.

These two issues have led to Evoenergy trialling an expansion of real-time control by integrating the transformers with on-load tap changes and an increase in the standard distribution transformer capacity for new estates. We are also trialling the integration of behind the meter DER into our Advanced Distribution Management System (ADMS) to allow real time monitoring of power quality as well as the option for our ADMS to actively manage inverter float voltage set-points directly or through aggregator intermediaries. The latter option will require new DER to be capable of remote monitoring and control.

In the longer term, we are investigating more innovative approaches to low voltage planning for these suburbs by considering the impact of reverse power flows in the design of network infrastructure and potential solutions. Such solutions comprise the mitigation strategies mentioned above as well as possibly increasing cable and conductor capacity, reconfiguring system topologies, and other mitigating measures to reduce these reverse power flows by absorption into batteries or load.

### 2.2.3 Research and development

We are also investing in research and development activities to understand how network constraints and network value can be considered within emerging distribution market platforms. We are currently undertaking a study to investigate how DER can be orchestrated via our ADMS integrated with a distribution market platform provided by a third party. The proposed solution has two core functions:

1) Ensures that DER dispatches not initiated by the network can be safely executed without violating the technical limits on the network; and

2) Provides a price signal back to the network for support services available from DER.

# 3. Pathways for DER to provide value

We believe that there are two pathways for DER to provide value to our customers.

### 3.1.1 Network services

The first pathway involves DER providing an efficient alternative to investment in the network. Utilising DER to provide demand management services can result in the avoidance or deferral of network augmentation. Likewise, voltage control services provided by DER can be utilised to achieve the required quality of supply. The regulatory framework allows us to make payment to third parties where these services can be delivered at lower cost than network solutions.

In our most recent regulatory proposal, we have identified approximately $1.8M of investment in demand management over five years with a potential additional up to $3M available under the Demand Management Incentive Scheme[2]. Despite the relatively small investment, the demand management proposed represents a step change in our demand management program. Rather than relying on traditional demand management methods such as curtailing large individual commercial customers or contracting large embedded generation, we will monitor and control behind the meter DER in new residential suburbs to provide demand management services[3]. We view this type of demand management as critical to our future network vision.

### 3.1.2 Increasing export potential by managing network issues

The second pathway allows for dynamic management of network issues to enable increased DER export and increased participation in energy markets (wholesale, ancillary services and emergency reserve markets) than would otherwise be possible.

The consultation paper envisages that the DSO will effectively constrain DER at a local level during periods of network and system constraints. This approach, when compared to cruder mechanisms such as blanket export limits, or reliance on the inverter protection systems, will enable greater export and hence market participation at other times, which when deployed at scale has the potential to reward DER customers as well as reduce energy costs for all consumers.

While Evoenergy agrees that the value proposition exists, this model requires a high level of participation of DER customers. Achieving a high level of participation is challenging, given that DER customers who do not participate will receive benefits (greater ability to export), while the participating DER customers are more likely to be constrained and receive reduced benefits. The solution will therefore either require regulation to enforce mandatory participation (which is unlikely to be readily accepted by customers) or must include carefully considered incentive mechanisms which allow for at least part of the value stream to flow to participating DER customers rather than the customer base as a whole.

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[2] Our total DMIS incentive cap is $1.5M which may be recovered by Evoenergy for demand management costs up to $3M.

[3] See Chapter 6 and Appendix 6.2 of our 2019 to 2024 regulatory proposal < https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/evoenergy-actewagl-determination-2019-24/proposal>

Additionally, in our view there is further value to be realised where the network (or potentially other flexible loads) can be actively engaged to alleviate the constraint (via approaches such as:

- Low voltage regulators;
- On-load tap changers;
- Network batteries;
- Direct control of inverter float voltage set-points; and/or
- Longer-term capital investments in reinforcing networks

These approaches will facilitate greater export without constraining any DER customers (or constraining to a limited extent).

The current regulatory framework does not provide clear guidance as to whether these investments can be capitalised, or to what extent we are able to invest in managing network constraints where these are caused by DER. Although yet to be tested, the regulatory framework will allow such investment where we can demonstrate that the economic benefits of greater export exceed the costs of investment.

We have not proposed any expenditure in our most recent regulatory proposal to address this issue, due to both the relatively small number of issues we are forecasting in the next five years, as well as the regulatory uncertainty. Notwithstanding, our investment in business and IT Systems (which stand up on an economic basis without considering DER benefits) included in our regulatory proposal will ultimately enable us to more actively manage network constraints.

# 4. Proposed Models for DSO Design

The AEMO/Energy Networks Australia Consultation Paper sets out three potential models for design of the Distribution System Operator (DSO). Our view is that each of these options have potential merits and shortcomings, but that the development path needs to evolve over time, aligned with the expected impacts of DER and their timeframes at all market levels.

There are near-term impacts which have already emerged within our low voltage network. These are expected to extend to medium and high voltages as the penetration of DER increases. Monitoring and control at the low voltage level will be required to avoid the adoption of coarse mechanisms such as export limitations or reliance on protection settings to constrain DER. In our view, DNSPs are ideally placed to undertake such monitoring and control and are already investing in the IT/OT infrastructure, field technology and necessary skills and expertise to achieve this.

In the near term, we see no value or need for AEMO to be involved in the DER orchestration process other than undertaking market settlements for DER aggregators participating in the wholesale, ancillary services or emergency reserve markets. DER participation in these markets is currently at very limited scale and is already enabled for the most part through the existing market design.

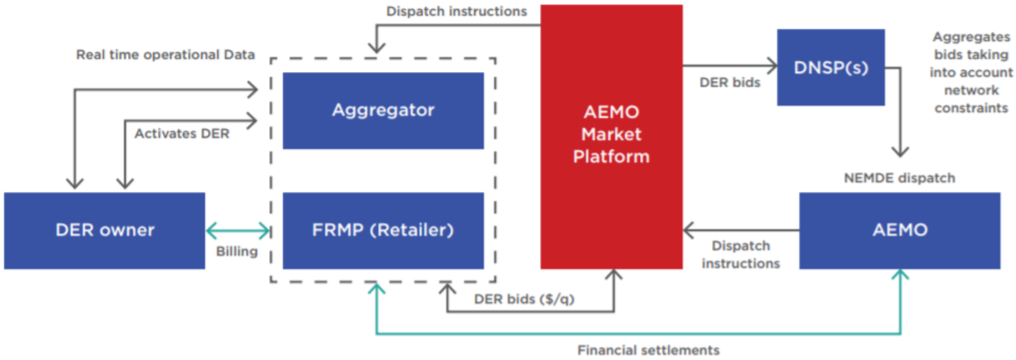
In our view, AEMO involvement in the DER orchestration process is not required until such time as battery storage or other active DER is present at sufficient levels to result in system level impacts if it is not centrally managed. The AEMO/Energy Networks Australia consultation paper suggests that this will occur when Virtual Power Plants (VPP) reach a certain threshold, requiring management of both system and network issues as part of the market dispatch process. While AEMO does not provide a timeframe for this, in our view this is not likely to occur in the short term and will depend upon the cost trajectory of battery storage technology as well as the level of support for VPP provided by State and Territory Governments.

Our specific comments on each of the models proposed in the AEMO/Energy Networks Australia consultation paper are outlined below.

## 4.1 Model 1 – Single Integrated Platform

Model 1, whereby AEMO is responsible for a central platform and optimises dispatch taking into account transmission and distribution network constraints (as shown in Figure 3) has several advantages as outlined in the AEMO/Energy Networks Australia Consultation Paper. Most importantly, it allows aggregators operating in multiple regions to interact with a single entity (AEMO) via a central platform.

FIGURE 3 – MODEL 1 (SINGLE INTEGRATED PLATFORM)




Source: AEMO / Energy Networks Australia

It should also be noted, however, that there are different drivers in each region both from a market and policy perspective, implying that the timing for the need for a centralised platform will differ between regions.

However, Model 1 reduces the role of the DNSP, effectively limited to:

- Providing information on network constraints to AEMO to enable dispatch; and
- Managing financial settlement of any network services provided.

In our view, network service providers need to have a far greater role in DER orchestration due to the localised nature of the network issue as well as to leverage the significant investment in IT/OT and skills and knowledge that networks have already made.

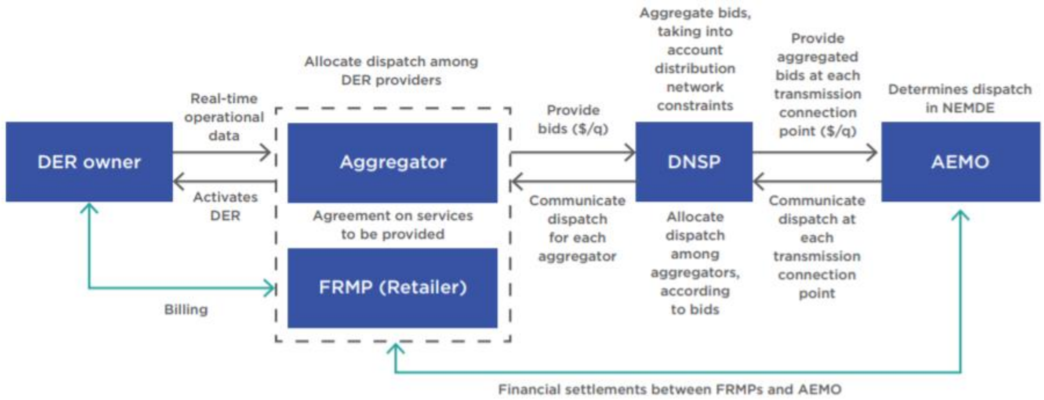
Further, we feel that there is an opportunity to manage the local network constraint using both network and DER responses and that this orchestration will need to be done at the local level. Aggregating responses at the transmission connection point whilst controlling at the local constraint areas introduces unnecessary complexity.

Only DER systems that can directly mitigate the localised problem can provide value. In our view there is no value in aggregating DER response at the transmission level (other than for market settlements) until their overall impacts at this level will be significant.

## 4.2 Model 2 – Two-Step Tiered Platform (DNSPs optimising distribution level dispatch)

Model 2, as proposed by AEMO/Energy Networks Australia (as shown in Figure 4) involves a much greater level of DNSP involvement by establishing a two-step tiered platform.  We consider that Model 2 offers more value in the initial stages compared to Model 1 because DNSPs will by necessity have developed systems that will forecast, monitor and control DER at the local level.

FIGURE 4 – MODEL 2 (TWO-STEP TIERED PLATFROM DNSP)



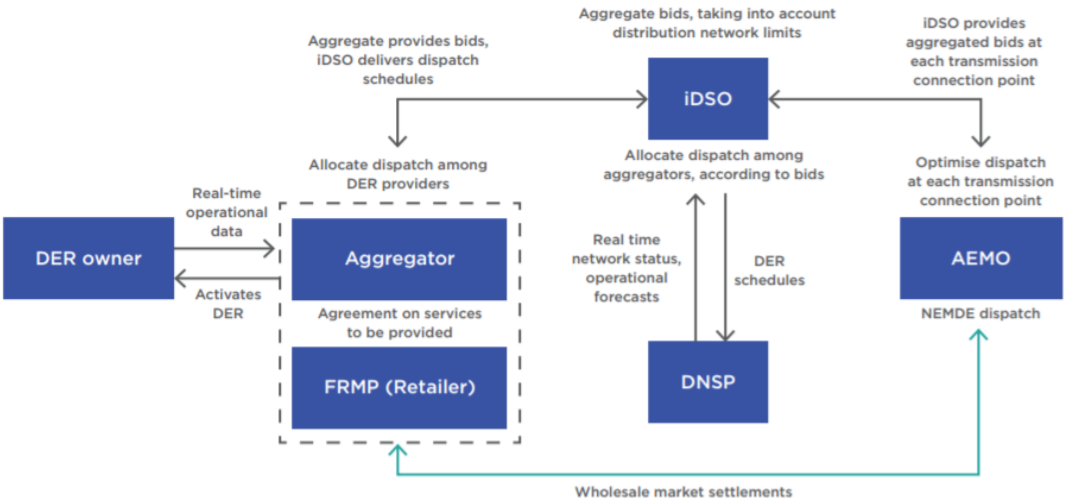

Source: AEMO / Energy Networks Australia

In order to manage DER, a DNSP will require a real time ADMS system (or similar) to forecast network constraints based on inputs such as customer load, temperature and cloud cover. The ADMS would automatically determine the level of DER generation required to meet the network requirements and dispatch or constrain generation accordingly. The DNSP would require an aggregator registration process as well as standards for connections to enable remote control and monitoring (as per AEMO/Energy Networks Australia 'no regrets' actions).

## 4.3 Model 3 – Two-Step Tiered Platform (independent DSO optimising distribution level dispatch)

Our view is that Model 3 (as shown in Figure 5) can deliver the same benefits as Model 2 but has the additional risks and benefits of involving a third party.

FIGURE 5 – MODEL 3 (TWO-STEP TIERED PLATFROM IDSO)




Source: AEMO / Energy Networks Australia

At this early stage of the evolution of DSO, Evoenergy is actively trialling a version of Model 3 (excluding the interaction with AEMO) over the next 12 months. The trial involves the utilisation of our existing investment in ADMS to dynamically forecast and identify network constraints at the low voltage level and utilise an existing third party IoT hub to communicate with outside providers.

### 4.4 Assessment against key principles

We support the key design principles as set out by Energy Networks Australia and AEMO. Our view of the relative advantages and disadvantages of the proposed models with respect to these principles is set out below.

TABLE 1 – ASSESSMENT OF MODELS AGAINST AEMO/ENERGY NETWORKS AUSTRALIA KEY PRINCIPLES

| Principle for framework design | | Evoenergy view |
|---|---|---|
| 1 | Simplicity, transparency and adaptability of the system to new technologies. | Model 1 has some advantages in terms of simplicity for aggregators operating in multiple regions.<br>However, the orchestration exercise under Model 1 aggregating responses to a transmission connection point level but controlling at the local constraint areas will introduce unnecessary complexity. |
| 2 | Supporting affordability whilst maintaining security and reliability of the energy system. | All models have the potential to provide affordability benefits where DER can be used more effectively to provide network services and participate in other energy markets.<br>Models 2 and 3 allow for greater visibility of DER by NSPs improving our ability to manage network constraints and improve reliability.<br>All models will address system security risks posed by DER. However, this is more likely to be a medium to longer term risk especially when compared to distribution network reliability. |
| 3 | Ensuring the optimal customer outcomes and value across short, medium and long-term horizons – both for those with and without their own DER. | Consideration should be given to a pathway approach, adopting Model 2 or 3 in the short to medium term and potentially expanding to Model 3 in the longer term where efficiencies are identified.<br>Consideration should also be given to the value delivered by a DSO and how this should be transferred to active DER, passive DER and non-DER customers (for all Models). |

| Principle for framework design | | Evoenergy view |
|---|---|---|
| 4 | Minimising duplication of functionality where possible and utilising existing governance structures without limiting innovation. | Model 1 has the potential to limit the innovation currently being delivered by DNSPs in their existing investments, investigations and trialling of DSO concepts. |
| 5 | Promoting competition in the provision and aggregation of DER, technology neutrality and reducing barriers to entry across the NEM and WEM. | Model 1 has benefits to aggregators operating in multiple regions by providing a single point of contact making participation simpler.<br>Model 1 also has the advantage of independence encouraging technology neutrality (although this could be managed with Model 2 or 3). |
| 6 | Promoting information transparency and price signals that encourage efficient investment and operational decisions. | All of the models proposed have the potential to provide price signals to customers (via aggregators) to more efficiently invest and operate DER systems compared to BAU.<br>However, none of the models proposed by AEMO/Energy Networks Australia send any price signals to NSPs to invest in network solutions to alleviate network issues caused by DER. In our view, this would be more easily achieved under Model 2 or 3 where both DER and network solutions are orchestrated at a local level. |
| 7 | Lowest cost. | Model 2 and 3 have the potential to leverage significant investment (existing and planned) in DNSP IT/OT infrastructure and skills and knowledge which may lower overall cost.<br>The need for the centralised system in Model 1 would result in additional costs to the energy system and it is not clear that these are warranted in the short to medium term. |

## 4.5 Preferred pathway

We consider that the expected impacts and their timeframes at all market levels should guide the development path to be undertaken. Based on this premise, Model 2 and/or Model 3 with limited involvement from AEMO are appropriate in the near term. NSPs including Evoenergy are already implementing and trialling elements of both Model 2 and Model 3. Model 1 may eventually be appropriate in the medium term where centralised coordination of DER is required to mitigate system issues.

# 5. Priority Actions

As DER penetration levels increase it will become increasingly challenging to enable our customers to receive full value for their investments in DER without orchestration. We therefore view the development of the DSO concept as fundamentally important to meeting our customers' needs. We intend to continue to investigate and trial appropriate mechanisms which both leverage our existing investments in business systems and IT and respond to our customers' needs particularly in new estates mandating 100% solar PV penetration.

Notwithstanding, we support the continued development of a national framework which enables management of DER to alleviate network and system constraints to be integrated with wholesale, ancillary services, emergency reserves and network services markets. We believe this work can occur in parallel with NSPs' own investigations with lessons learned shared amongst all parties.

The following priority actions set out our view as to the next steps AEMO/Energy Networks Australia should take in order to progress the national framework:

1) Building understanding of network constraints – Work with network service providers to identify the timing and extent of low voltage, medium voltage and high voltage network issues which are likely to emerge given forecasts of DER penetration;
2) Building understanding of system constraints – Work with network service providers and AEMO to establish the timing and extent of system issues which are likely to emerge;
3) Undertake an economic assessment – Quantify the costs and benefits of the DSO concept compared to the other cruder mechanisms (such as export limitations and export constraints via protection settings) to manage network issues caused by high levels of DER penetration. This is particularly important to network service providers who are seeking funding via the regulatory framework to invest in early pilots and trials of DSO to manage network issues;
4) Customer benefits – Set out the benefits of the roadmap proposed to customers including active DER customers (subject to monitoring and control), passive DER customers (not subject to monitoring and control) and non-DER customers. This should include consideration as to how incentives or mandatory settings will work to encourage high levels of active DER.
5) Develop a roadmap – Set out a roadmap for the development of the DSO design which allows NSPs to continue to invest, investigate and trial DSO mechanisms in the near term adopting variants of Model 2 and Model 3; and

We further support the other "no regrets" actions as set out by AEMO/Energy Networks Australia for the development and implementation of standards for DER monitoring and communication. The implementation of such standards is imperative to achieving critical mass of DER which is able to participate in orchestration.

In addition, in our view, there are a number of challenges which are yet to be fully considered by Energy Networks Australia and AEMO which are critical to a well designed DSO framework. These include:

1) The potential for network actions to alleviate constraints (such as low voltage regulation, power electronics, on-load tap changers, management of other

flexible loads) to be incorporated within the DSO design and the value of such a mechanism to release additional export potential;

2) The barriers to network owned DER (such as network batteries) participating in the DSO concept;

3) The way in which DER customers will be incentivised to participate in the DSO to ensure a critical mass of DER is recruited and at the same time enabling benefits to be returned to the overall customer base; and

4) The integration of tariff arrangements and the DSO design. (We note that further consideration of tariff reform has been specifically excluded from the Consultation Paper. However, we believe that the DSO model should identify the potential for flexible loads, such as EVs and battery storage systems, to be utilised to alleviate network constraints. This will require consideration of the way in which the DSO concept integrates with tariff mechanisms.

We believe that orchestration of DER along with active management of network constraints has the potential to provide value to all customers and the energy system as a whole. Quantifying this value is essential to both the continued progress of the Open Energy Networks and DSO concepts as well as to enable network service providers to appropriately invest via the regulatory framework. We welcome the opportunity to further discuss any of the above and contribute to the priority actions moving forward.