Ms Victoria Mollard
Director
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

19 January 2017

Dear Ms Mollard

Distribution Market Model

CitiPower and Powercor welcome the opportunity to respond to the Australian Energy Market Commission's (**AEMC**) Distribution Market Model Approach Paper (**Approach Paper**).

The uptake of controllable distributed energy resources (**DER**) will bring opportunities and risks to distribution networks. The market design for DER related services should lead to the efficient deployment and use of DER, while minimising network costs associated with its operation. It is likely this will be best achieved through market mechanisms and efficient price signals.

In this submission we:

- consider DER's impact in driving network costs, and the benefits it will provide through new network support services;
- support price signals to encourage efficient DER deployment, although we consider there is a continuing role for traditional solutions to manage supply and demand imbalances and DER technical issues;
- consider distributors should be responsible for managing the technical impacts DER places on local network areas;
- highlight the potential need for market mechanisms to measure and reconcile DER service delivery; and
- provide information on DER's technical impacts.

This submission can be read with our submission to the AEMC's Electricity Network Economic Regulatory Framework Review (**Framework Review**), which outlines the barriers in the electricity framework to efficient DER deployment.

If you have any queries on this submission, please contact me on (03) 9683 4465 or bcleeve@powercor.com.au.

Regards

Brent Cleeve

Brent Cleeve
Head of Regulation

Distribution Market Model

1.1 Smart DER

The AEMC has focussed its Approach Paper on 'smart' DER that can be controlled and automatically respond to market conditions and prices.

Most DER currently being installed is not smart DER and the electricity framework is not promoting the efficient installation and use of this DER. We understand however these more immediate framework issues are within the Framework Review's scope, and so it is appropriate to focus on smart DER in this consultation.

1.2 DER's network impact

DER's penetration will continue to increase, particularly in networks like Powercor's that are conducive to it. Integrating DER will increasingly drive network costs but will also provide new opportunities for distributors to manage network constraints in non-traditional ways.

1.2.1 Network costs from DER

The Approach Paper correctly identified the technical impacts from DER on the network—voltage and frequency stability, harmonics, flicker etc. Across our network, overcoming these impacts (particularly from solar PV) is increasingly driving the need to augment our network through:

- replacement of existing regulators with bi-directional regulators to manage reverse power flows; and
- management of voltage issues necessitating local augmentations of distribution transformers, or the ongoing changing of taps on distribution transformers.

DER has also caused network voltage levels to exceed the standards outlined in the Victorian Electricity Distribution Code at several locations—although this has resulted in few complaints to date.

In 2016 we requested ENEA to investigate the network impact of DER drawing on international experience. ENEA conducted interviews with local and German distributors (in Germany more than 50% of generation capacity is connected to the distribution network) and found voltage variation and reverse flows are the two most significant technical network impacts. Reverse flows have been encountered in Germany up to four times maximum demand. According to the German utility EnBW, more than €10 million was spent between 2009-2014 for grid development and connections.[1]

As DER becomes 'smarter' we expect it to drive more network upgrades by reducing load diversity on our network. For example, third parties may coordinate DER's deployment in order to sell generation or load control services to other parties. At the zone substation level our network is able to manage the impact of load changes on voltage through the use of on-load tap changers. This is not the case at the distribution transformer level, meaning localised impacts will need to be mitigated in some way.

Greater smart DER penetration—leading to more frequent and potentially larger technical impacts—may also drive the need for network monitoring at the connection point, such as:

- metering—higher DER penetration may require live or near live monitoring to ensure the network is operating within its limits. Subject to metering contestability outcomes, we could use our Advanced Metering Infrastructure (**AMI**) to measure power flow, voltage and power factor. However the system is not intended to provide instantaneous data, meaning it can be delayed from 30 minutes to 4 hours. Live information would require upgrading Access Points and Relays installed on our poles. Alternatively other monitoring equipment would be needed;

1 ENEA, Distributed generation REPEX value, November 2016, and ENEA, Distributed Generation Network Value, March 2016, Appendix 3.

- IT—we currently only record steady state voltage variations at the customer level during targeted trials or when initiated by our customers. This reflects our best endeavours to assess and record the nature, location, condition and performance of our assets in a way which minimises costs to customers. Recording, retrieval and storage of steady state voltage excursions for each customer would require IT system upgrades; and
- control room—to manage additional network information and develop operational responses to the use of DER across our network is likely to result in additional control room resource requirements.

In our response to the Framework Review we discuss network expenditure models, such as the Transform Model used in the United Kingdom, as a tool to help ensure expenditure is minimised and efficient.

Given the costs from DER, it is important for future market models to ensure DER is deployed in ways that maximises its benefits.

1.2.2 Network benefits from DER

DER currently provides very limited network benefit due to the way it's being deployed. Customers are naturally focused on reducing their own energy bills and therefore the locations and times that DER is deployed are not targeted towards network (or market) constraints. The framework barriers leading to this inefficient deployment are discussed in our Framework Review submission.

In our submission to the Essential Services Commission's Inquiry into the True Value of Distributed Generation, we provided modelling demonstrating the impact of solar PV and batteries on deferring augmentation. We found that over the next 10 years DER could have a material augmentation deferral value on 2 of our 105 zone substations, and could provide some value on a further 6. We also found that if DER take-up is higher than forecast, perhaps in response to efficient deployment signals, it could provide value to a further 6 zone substations.[2] While over the next 10 years we do not expect the value of DER in deferring augmentation to be substantial, our analysis demonstrates that encouraging efficient DER deployment can increase its network value, which may become increasingly important when we next experience a period of strong demand growth.

DER deployment could also be used to mitigate the same technical impacts it is currently creating (e.g. voltage exceedance)—discussed more in table 1. This would provide an alternative to traditional network capital expenditure.

1.3 Efficient DER deployment

1.3.1 Principles for good market design

The Approach Paper outlines six principles for good market design.

Principle 4: Promote price signals that encourage efficient investment and operational decisions

We have a preference for the use of price signals to encourage efficient DER deployment. Market prices would take account of the interactions between DER services. For example, a retailer or third party may procure localised generation to offset peak generation costs, however, this could drive thermal network constraints and voltage variations. Distributors may simultaneously need to procure the opposite service (i.e. constraining localised generation) for network stability. The highest value service—which in this example is likely to be network support—would be delivered. Over the longer term, the market may devise ways to offer both services without them conflicting to capture both value streams.

Market prices could also account for different DER values based on location and time of use. To do so, price would need to be 'live' reflecting current market conditions rather than 'cost reflective' based on average DER service values.

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[2] CitiPower and Powercor, submission to the ESC's Inquiry Into the true value of distributed generation: Network Value Discussion Paper, 29 July 2016.

Within a market price system there would need to be scope for contracting. Once a distributor has identified that DER could provide local network value, price certainty for the DER service will become important given distributors' revenue cap constraints and incentives to be efficient.

The Approach Paper outlines that price signals may help to align local supply and demand, and mitigate the need for 'traditional' solutions to address technical issues.[3] We agree, although consider price signals may not abdicate the need for traditional solutions altogether. For example:

- network expenditure—where DER provides wholesale benefits and creates network constraints, network expenditure may be needed to integrate DER and derive the (net) wholesale benefit;
- technical solutions (e.g. standards)—new standards setting a common communication language for DER devices would reduce the cost of procuring it; and
- operational solutions (e.g. constraining DER)—may be a necessary safeguard for network safety and stability.

Principle 2: Promote competition where feasible

Competition will generally improve consumer outcomes over the long term, but not always. Where there is little chance of *effective* competition, seeking to promote competition at the expense of achieving lowest cost delivery (combined with regulation) can be inefficient and increase prices. Additionally, safeguards that displace competitive market outcomes are sometimes needed to ensure the effective and safe operation of networks.

We believe the principle could be re-worded as 'Promote competition where *in the interest of consumers*'. This better aligns with the National Electricity Objective.

1.3.2 Role of distributors

The Approach Paper asks which institutions should manage the distribution system's operation in the face of additional DER services and resultant technical impacts.

The responsible party should depend on the nature of the technical constraint. We believe that distributors should manage the impacts on localised network areas. This is because distributors:

- own the network assets and therefore should have control over the operational management and the technical stresses put on them;
- have obligations placed upon them, for example under the Victorian Electricity Distribution Code, to stay within technical constraints; and
- have access to up-to-date network information which will enable short term forecasting and balancing.

Only where the DER service affects the wider network (e.g. multiple distribution networks or the transmission network) and would create coordination challenges, would it be appropriate for a central body to have responsibility for the constraint. More information is provided in table 1.

1.4 DER service delivery

An effective DER market requires participants to be sure that services procured are actually delivered. This may not be problematic for purchasing localised generation or curtailing load because these power flows are metered. However it could be for new DER services such as voltage support and frequency stability.

A future market design may need to consider measurement and reconciliation mechanisms. Additionally, consideration could be given to situations where a requested service is not provided and who is responsible for any resultant safety and technical impacts to networks and customers.

[3] AEMC, Distribution Market Model, 1 December 2016, p. 24.

1.5 Summary table of DER technical impact

To inform the Approach Paper, for each of the technical impact, the following table outlines whether:

- the impact is localised or system wide;
- DER can be used to manage the technical impact (or only creates it); and
- ways to overcome the technical impact.

Table 1 DER technical impacts

Technical impact	Network impact	Can DER be used to mitigate the technical impact?	Overcoming technical impacts
Voltage stability	Localised impact—can be managed by distributors	Yes	Discussed in submission above.
Frequency stability	System wide impact—managed by AEMO	Yes	DER inverters able to respond to frequency control requirements could assist to improve frequency stability.
Harmonics	Localised impact—can be managed by distributors	Through restricting DER or the use of specialised inverter harmonic control algorithms	Currently it is not feasible to monitor the harmonic output of all NMIs to determine which customers' equipment (including for example a solar PV system) may be causing harmonic issues. If harmonics are above the allowed and safe range, traditional network expenditure is currently the only practicable way to fix the problem. Specialist inverter control has been used in larger systems to actively combat harmonics, but this is not expected to be a technical offering of consumer level DER.
Flicker	Localised impact—can be managed by distributors	No	Flicker cannot be mitigated by DER as it would not be able to react quickly enough. Requires network augmentation.
Power factor	Localised impact—can be managed by distributors	Yes	DER with suitably fast and controllable inverters can act to improve power factor. Together with power factor correction equipment installed by larger customers in response to tariff changes, this may lessen the need for capacitor banks in the future.
Thermal overload	Localised impact—can be managed by distributors	Yes	Discussed in submission above.

Technical impact	Network impact	Can DER be used to mitigate the technical impact?	Overcoming technical impacts
Islanding and reclosing	Localised impact—can be managed by distributors	NA	Islanding could reduce outages by allowing locally generated electricity to service households. Currently, it is not feasible because: safety— • with multiple sources of supply down-stream on the network we would not be able to confirm if the network was de-energised prior to undertaking any maintenance work; and • under fault conditions, once the network protection operates the fault will remain energised from islanded DERs. technical— • islands would lose synchronism with the remaining network quickly. Existing network equipment would not withstand the reconnection of unsynchronised networks and therefore islands would either need to be fully de-energised prior to reconnection or significant network augmentation would be required; • as the majority of DERs would be connected single phase, this would create phase imbalance and issues for customers on the remaining network as groups of DER’s islanded; • the majority of existing inverters are designed to work with network supply and will trip in its absence; and • distributors would be unable to manage power quality within the islands.
Protection	Localised impact—can be managed by distributors	Only through restricting DER	Should DER penetration become too high, distribution networks would require significant upgrades to be rated for higher fault levels. Also, as noted above, fault detection and fault clearance would be problematic with DERs that are able to create islands within the network.