Centre for Energy and Environmental Markets

# DISTRIBUTION MARKET MODEL

## Submission in response to the AEMC's Distribution Market Model draft report

AEMC Project Number SEA0004

by
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# About CEEM

The UNSW Centre for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from the Australian School of Business, the Faculty of Engineering, the Institute of Environmental Studies, the Faculty of Arts and Social Sciences and the Faculty of Law, working alongside a number of Australian and International partners.

CEEM's research focuses on the challenges and opportunities of clean energy transition within market oriented electricity industries. Key aspects of this transition are the integration of large-scale renewable technologies and distributed energy technologies – generation, storage and 'smart' loads – into the electricity industry. Facilitating this integration requires appropriate spot, ancillary and forward wholesale electricity markets, retail markets, monopoly network regulation and broader energy and climate policies.

CEEM has been undertaking research into these challenges for more than a decade, with a focus on the design of markets and regulatory frameworks within the Australian National Electricity Market, and State and Federal energy and climate policy. More details of this work can be found at the Centre website – www.ceem.unsw.edu.au. We welcome comments, suggestions and corrections on this submission, and all our work in the area. Please contact Associate Professor Iain MacGill, Joint Director of the Centre at i.macgill@unsw.edu.au.

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## Context and Remarks

CEEM welcomes the opportunity to contribute to this important consultation process which is part of the AEMC's exploration of whether present energy market arrangements are sufficiently flexible and resilient to effectively respond to technology change. The past decade has highlighted the rapid progress and uptake possible with small-scale, distributed, consumer focussed technologies. For an industry supposedly tasked with serving the long term interests of consumers, there has been remarkably little interest in facilitating genuine, active, consumer involvement in the delivery of their energy services. Consumers are now increasingly taken matters into their own hands, a commendable outcome but one that requires better coordination as deployment of distributed energy resources continues to grow. 2017.

Distributed energy resources (DERs) seem likely to play an increasingly key role in Australia's energy future. The increased uptake of distributed generation (DG), specifically photovoltaics (PV), is leading to innovation in how electricity is generated, used and sold – which is leading to greater choice for consumers. This is expected to grow with declining, and hence increasingly competitive, DG costs and changes in facilitating technologies including storage, advanced inverter functions, smart loads, smart meters and mini-grids.

High levels of uptake of distributed solar PV have already changed the public conversation regarding electricity and the individual customer's role. The new technologies that are becoming available, and the broader energy transition required for a sustainable energy future (including the complete decarbonisation of the electricity sector that is required to avoid dangerous global warming), mean that engaging with consumers is more important than ever. We support the AEMC's contributions to date in undertaking forward looking investigations and establishing public consultations regarding the future opportunities and challenges of a more distributed energy system. The Distribution Market Model Draft Report published by the Commission captures many of the key issues and provides a useful starting point for the longer-term conversation now required concerning a market-oriented distributed energy future.

However, we believe the exclusion of a number of critical issues from the scope of the work to date could affect its ability to provide a strategic framework that can inform AEMC responses to emerging issues. In particular, we suggest that the Commission consider broadening the scope of its review to include:

- The critical need for community engagement and a strong emphasis on managing complexity to appropriately facilitate distributed energy options
- The possible role of alternative network arrangements including embedded networks in broadening the opportunities for consumers to engage with the electricity industry in a more coordinated and hence valuable way
- A broader definition of DERs, which includes a much wider range of possible energy consumer choices including energy efficiency as well as the more active options that the AEMC has focused on to date
- The need for the NEM to transition to zero net emissions within a matter of decades if Australia is to fulfil its commitments towards avoiding dangerous global warming

Our thoughts on scope are set out below, along with a note regarding the Commission's definition of key terms. We then address the specific questions raised in the AEMC discussion paper.

## *Community Engagement and Complexity*

It is widely accepted that the electricity system is changing, both at a utility scale as the sector undergoes decarbonisation, including significant deployment of variable renewable energy; and also at the distribution level as consumers are offered an ever growing number of opportunities to change the way in which they use and produce electricity.

Through this process it is likely that there will be 'winners' and 'losers. In particular, there may be different impacts on the bills of different types of consumers. Throughout this transition, it is important to maintain safety, security, reliability and affordability in an equitable manner. However, it is also important not only to give consumers choice, but to empower consumer decision-making and maintain social license, including supporting consumers and communities to pursue solutions of their choice and in which they can see value. By necessity, it is critical to aim for simplicity in order to effectively engage consumers. It is also important to recognise that their choices may not always be optimising decisions, and therefore, even if prices are fully cost reflective, may not always be economically efficient.

We support facilitating access to the various services distributed energy resources (DERs) can provide, potentially through some kind of market with multiple buyers and sellers. However it is important to acknowledge the limitations of market structures in this particular context. Energy provides for basic needs, so the electricity system is inherently 'social infrastructure' and delivers a public good. Conversations regarding its future must be couched in terms of social acceptability and the perception of fairness as well as overall efficiency.

One key point to note is that the motivations and sentiment behind co-operatives and community energy projects do not 'fit' well into market structures. That is, the concept of community building is quite contrary to that of competitive forces. Indeed, it is through community building and a sense of collective ownership that social license can be maintained, despite significant changes to the sector. While we support in principle the monetisation and optimisation of various DER services, we seek an increased emphasis on social license and collective ownership in the Commission's thinking.

## *Alternative Network Arrangements*

The Commission's principles of good model design include the promotion of competition. However, it seems to be assumed that network infrastructure will continue to be provided exclusively by DNSPs. While we are agreed that the distribution network has historically been a pure natural monopoly, it is now becoming clear that DERs are capable of providing competition for networks in the provision of some types of 'network services'. A 'competitor' may be defined as (i) something that competes for the same revenue or reduces network revenue, and either (ii) something (such as energy efficiency or demand side management) that reduces the need for what the networks offer, or (iii) something that provides an alternative to what networks offer (i.e. the need is still present but there is now an alternative supplier, such as distributed generation).

Facing such competition means that, by definition, networks are no longer pure monopolies. Of course, networks still have a major role in providing an essential public service, and still have significant powers to limit competition, and so still require careful regulation. However it is clear that the context for regulation of networks has changed. The required changes to regulation include allowance for the fact that, as electricity generation shifts from a centralised to a distributed model, other regulatory arrangements, including alternative performance-based regulatory incentives, can contribute to greater efficiency in maximising the value of distributed energy resources – and hence reduce costs for all concerned. Note that even if they are not the 'optimiser', DNSPs may be conflicted e.g. the preference for CAPEX over OPEX is likely to persist without more fundamental regulatory reform.

The MIT *Utility of the Future* Report argues that a level playing field for all resources requires that cost-reflective electricity prices and regulated changes should be based only on what is metered (ie. injections and withdrawals) at the point of connection to the power system rather than being dependent on what technologies might lie behind the meter. They should also be symmetrical; that is, power injection at a given time and place should be compensated at the same rate that is charged for withdrawal (consumption) at the same time and place. This has implications in terms of connection points, as well as competition for provision of network services.

Of particular relevance to other AEMC deliberations, there are significant groups of consumers, including residents of apartment buildings and rental properties, who have very limited energy choices, and are currently unable to utilise distributed energy resources even to provide customer services behind the meter. The potential for these customers, acting individually, to sell network or wholesale services into the grid is remote. In some circumstances, embedded networks could facilitate the degree of co-ordination required to enable these groups to fully utilise distributed energy resources such as rooftop photovoltaics or battery storage. Similarly, micro-grids for strata- or community-titled housing schemes or edge-of-grid communities could facilitate aggregation to enable groups of consumers to more efficiently realise the value of DERs by selling energy services into the distribution network.

A technology-neutral Market Model should allow for a broad range of distribution arrangements and business models, including embedded networks, micro-grids and off-grid arrangements. Notwithstanding the Commission's ongoing *Review of regulatory arrangements for embedded networks,* and its separate consideration of specific aspects of off-grid supply through its assessment of Western Power's *Alternatives to grid-supplied network services rule change,* the exclusion of these alternative distribution arrangements from the scope of the Market Model could impose unnecessary constraints on the future development of the network, at the expense of efficient outcomes for consumers.

### *Definition of Distributed Energy Resources*

We acknowledge that the Commission considered comments regarding the definition of Distributed Energy Resources (and other key terms) through the Approach Paper consultation process. Nonetheless we do not agree with the Commission's definition as proposed in the Draft Report. Specifically, we believe that the definition of Distributed Energy Resources should include 'passive' elements such as solar PV as well as broader energy consumer options such as energy efficiency.

- In the context of no peak load growth, DER value to networks may be in reducing REPEX, requiring predictable overall load reduction that can be provided by 'passive' technologies such as EE and PV. Under probabilistic planning, this will reduce the risk of unserved load and therefore defer augmentation expenditure. Investment decisions about how to provide energy services (end-use equipment decisions), including those that are largely 'passive' are important, as loads can provide different levels of inherent storage, flexibility and differ in their typical schedule of use and the extent to which they are weather dependent.
- Technologies connected via inverters are capable of providing network services such as reactive power control and curtailment in response to real time signals.

- Whilst passive elements (by definition) currently cannot respond to price signals, this is not necessarily always going to be the case. The Commission acknowledges this fact however has chosen to define DERs as '*An integrated system of smart energy equipment that is connected to the distribution network.*' Given that the DMM is intended to be a forward looking, strategic thought piece, we believe it would be advisable to include passive elements within this definition. At a minimum, it is recommended that careful consideration is given to the evolution of current passive elements and how these could interact with the proposed DMM.
- Indeed, the uptake of batteries, active Home Energy Management Systems and options that allow active trading in the market (eg. Reposit) are strongly associated with, and integrated with, the uptake of solar PV. This is because: (i) PV is cheaper than batteries so the 'first movers' install PV first then extend that interest into battery installs, (ii) although batteries on their own may result in a payback that is too long, when combined with PV the payback is reasonable, and (iii) exported PV electricity is often paid less than the retail rate and so batteries are used to minimise PV exports.
- AEMC's definition of 'optimise' includes efficient decisions about investment in and operation of DERs. Investment decisions with regards to passive elements can be influenced by market signals. PV generation is related in predictable ways to weather and load patterns, and it is therefore efficient to provide PV investors with exposure to temporally variable price. Even if PV is not equipped to be 'smart' it should still be able to participate in markets, in the same way as generators with limited or no flexibility, such as coal or nuclear participate in wholesale energy markets. Further, as noted by the Commission in the Draft Report, passive equipment can '*affect network operation and drive the need for evolution.*' It is therefore critical that passive elements are brought within the scope of the project.
- As flagged in the Draft Report, it is widely accepted across the industry that DER includes solar PV.
- More generally still, market signals and regulated charges imposed on energy consumers should facilitate appropriate decision making across all their energy use decisions including particularly energy efficiency options. Indeed,

energy efficiency options are amongst the most promising for helping energy consumers reduce the costs of their energy services.

## *Low carbon transition*

We appreciate that the AEMC takes the view that *Consistent with the NEO and the Commission's approach to applying the energy objectives, this project will not consider the achievement of environmental or social objectives.*

However, we do not consider this position is still defensible given the need for the Australian NEM to entirely decarbonise within a matter of decades if Australia is to fairly contribute to global efforts to avoid dangerous warming. The Australian Government has committed to this goal through the Paris agreement, and appropriate electricity industry arrangements will be critical to facilitate the rapid transition required. DERs include a range of low and zero carbon generation sources as well as highly energy efficient end-use equipment. As such, frameworks for their deployment need to reflect the role that they can play in rapid decarbonisation. In this context, the focus needs to be less on regulatory and market optimisation within the present limited perspective taken by the AEMC for the NEO but, instead, a robust set of market and regulatory arrangements that can deliver the long-term interests of consumers across  equity, security and environmental outcomes.

As just one example, present AEMC efforts towards more cost reflective tariffs actually risk making overall market arrangements less efficient because the present market has extensive unpriced externalities. Markets with unpriced externalities are inefficient by design. While volumetric consumption based (kWh) network tariffs may not accurately reflect network costs they do reflect, in large part, emissions costs which are primarily generation (hence consumption) based. At present our market doesn't explicitly price environmental emissions. Changes to network tariffs to reduce their volumetric component may, hence, perversely actually reduce the efficiency of price signals to energy consumers in this regard. If the AEMC is seriously focussed on overall NEM efficiency then it has to engage more meaningfully in such interactions across the diverse long-term interests of consumers.

# Question 1 – Cost reflective Network Tariffs

***Question 1: Do stakeholders consider that there are any other barriers to the development and implementation of cost-reflective network tariffs? How material are these barriers? Are there other means for them to be addressed?***

Policy makers and the AEMC have argued that tariffs which better reflect the various costs of serving different types of consumers would put customers at the centre of future decision making. This should ensure that customers cover the costs they cause and, very importantly, now see price signals that incentivise efficient investment and operation of their own loads, storage and distributed generation.

The practical application of cost-reflective tariffs, however, is more challenging. One question is which costs need to be reflected – past (sunk), present (short-run marginal) or future (long-run marginal costs). Past cost recovery is an important aspect of network business financial sustainability while present costs are relevant to efficient operation of existing assets. Future costs are, however, the key costs in terms of incentivising efficient investment for the longer-term efficiency of network services. They are, however, inherently complex and fundamentally problematic to calculate. These costs are also very location-specific and invariably change over time.

As such, many of the existing DNSP efforts towards more cost-reflective tariffs have been anything but truly cost reflective. Many of the tariffs that have been proposed appear more focused on maintaining network revenue than incentivising efficient investment by both energy consumers and network businesses, and involve higher fixed charges (which are unavoidable and so ineffective at driving change)[1], specific solar charges[2], steep declining block flat tariffs, and even where demand

[1] Importantly, the economic argument for residual costs to all be assigned to a fixed charge is based on the assumption that there has always been a marginal price signal in place that, over time, has assigned the cost of network augmentation to those responsible for it. Clearly this is not the case and so assigning all residual costs to a fixed charge would place an unfair cost burden on those least responsible for the size of the network.

[2] Although solar PV has received considerable attention regarding potential cross subsidies because of volumetric tariffs, these are dwarfed by the subsidies between households with and without air-

charges are used, these are applied to the customer's peak demand rather than to the customer's demand at the time of the network peaks (which in aggregate is what causes the network peaks). The outcomes have, unsurprisingly, been contested as a range of stakeholders and the AER review these proposed tariff structures. The AER has recently stated:

*"An important element to setting a cost reflective demand charge is to ensure that customers are not charged a peak demand when they are not contributing to it. We consider demand charges should send signals to customers when their usage or peak consumption matches the peak on the network."* (AER's Final Decision of TSSs of NSW DNSPs, p53)

and

*"We encourage distributors to investigate alternative measures of demand for the next round of tariff structure statements having regard to each measure's ability to send price signals to customers that are more closely aligned with peak demand and utilisation on the network, rather than aligned with the individual customer's peak demand."* (AER's Final Decision of TSSs of NSW DNSPs, p139)

There is no shortage of detailed analysis on tariff design, which requires not only cost-reflectivity but also fairness (e.g. the reports for the AEMC by The Brattle Group and NERA Consulting in 2014). The main barriers to cost-reflective and fair tariff design appear to be the complexity of the task, and the competing interests across past, present and future cost reflectivity.

We have written a detailed journal paper describing a method to evaluate the cost-reflectivity of network tariffs (in terms of their ability to signal long-run marginal costs), and how to use this method to design them. This is currently under journal review so is not publicly available, but can be provided to the AEMC on request.

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conditioning (estimated by the Productivity Commission at $300 per year), and urban versus rural households.

Of course, the development of a cost-reflective tariff offering is just the first step. For such a tariff to be effective, it needs to be taken up by customers, who are then willing to stay on that tariff as well as able to respond to it appropriately. A perfectly cost-reflective tariff would include time and locational components, making the final tariff complex to understand. This would limit consumers' ability to interpret and hence respond to the price signals delivered. Network investment is a 'lumpy' cycle wherein incremental energy use does not result in materially increased network spend until a 'tipping point' is reached. It is difficult to accurately reflect this in a manner that will not deliver bill shock to consumers.

Thus, 'perfectly' cost reflective tariffs are not necessarily a feasible outcome. Some level of smearing across different locations and consumer groups is necessary in order to maintain the electricity industry's social license. It is instead important to consider appropriate tariffs on a spectrum of cost reflectivity, such that they deliver a clear price signal to consumers to engage in beneficial behaviour.

Allowing consumers (or their agents) to see the breakdown of network and energy components in their bills may reduce the distortion of the price signals, and allow consumers to better respond. In addition to this, the social and technical constraints need to be acknowledged. If consumers are not well educated about their contribution to network peaks and how this can be mitigated, they are unlikely to be able to assess whether they should change their behaviour. If tariffs are to be a tool to better engage energy consumers in the efficient provision of their energy services, the supporting metering and response technologies need to be far more widespread than they currently are.

Finally, as the MIT Utility of the Future study emphasises, cost-reflective tariffs should also be symmetrical; that is, power injection at a given time and place should be compensated at the same rate that is charged for withdrawal (consumption) at the same time and place. The AEMC appears to be a long way off accepting the implications of this for competition in network services and future network regulation.

## Question 2 – 'Missing markets' and 'missing prices'

***Do stakeholders consider that there are any 'missing markets' or 'missing prices' beyond those that will be implemented through cost-reflective network tariffs? If so, what are these?***

As noted above, we request that the Commission considers broadening the scope of study beyond an examination of a Distribution Market Model to encompass alternative distributed structures such as community or co-operative energy.

As flagged by the Commission in section 4.4 of the Draft Report, if dynamic optimisation of DER investment and operation were to occur consumers would be:
*"…exposed to increased basis risk, so thought would need to be given as to how parties might hedge against such risks."*
We support this view and particularly the importance of investment certainty for consumers. Furthermore, it is not just an issue under the AEMC's dynamic optimisation stage. The importance of investor certainty is well appreciated at the utility level, and there are a range of financial instruments that allow investors to secure future pricing that provides some measure of risk management. By contrast, DER investors currently have little assurance regarding future network tariffs (which are currently undergoing potentially major transition as noted above) or retail contracts, which are also generally only a few years of duration. DER investments have significant risks in these regards and instruments that can provide some level of risk management out to a decade or more are almost certainly going to be required for efficient investment to occur. Such arrangements are also required before the final stage of evolution (stage 3: dynamic optimisation) is reached. We acknowledge that simplicity will be necessary for consumers to engage in such a market, and that Energy Service Companies (ESCOs) may be best placed to manage this risk on behalf of consumers.

Quantifying the value that can be delivered by DERs without limiting the parties which can deliver that value is a crucial aspect of the Distribution Market Model. It is therefore critical to consider what services may be delivered and traded in this market, and what value they may represent. We support the thinking the Commission has set out in the Draft Report regarding these potential values.

However note that there is a critical balance to be struck between market efficiency and complexity for consumers.

At present, the market for demand side management is quite underdeveloped, and is generally comprised of loads of sufficient size to bid into the NEM. However, this approach fails to consider the cumulative effect of many small DERs acting in concert, which may be as effective at reducing peak demand as one large load. As an example, DERs in the form of controlled loads could reduce peak demand at critical times. At present, there is little scope for such opportunities to be considered. In addition, there appears at present to be little scope for the locational benefits of DERs to be monetised. In order to facilitate the development of DERs in the most beneficial locations, where they can deliver the most valuable services, this value needs to be included. It is known that the capacity constraints of the network are not uniform – different locations will have different levels of constraint, at different times of day.

Different forms of DERs will have differing value in areas of network constraint. An initial attempt to address some of this matter was made in the local generation network credits (LNGC) rule change submission, but it did not address all of the potential values that DERs could represent to networks. In order to better signal where investment in DERs is likely to be beneficial, the introduction of locational price signals will be necessary. Open access to information, particularly regarding network constraints and therefore potential DER investment locations is therefore highly valuable, as discussed further in Question 3.

In general, the locational granularity required for a DMM to be at its most effective does not appear to be well considered. The existing market model was built based on the technological limitations present more than 20 years ago, and has failed to develop and fully capitalise on the capabilities now possible. The development of nodal pricing at a far higher granularity may be complex, but it is well within current technical capabilities, and would deliver a far more beneficial outcome in the long run.

Finally, the NEM might fairly be characterised as Australia's largest externalities market given its contribution of around 35% of Australia's greenhouse gas emissions, as well as a wide range of other environmental impacts, none of which are efficiently priced at present. Markets with unpriced externalities are of course inefficient by definition. Some estimates of the social cost of carbon such as those of the US EPA suggest that the NEM may actually have greater environmental externality costs than direct costs from generation and network investment and operation. In this case, the greatest opportunities to improve NEM efficiency actually lie in improving environmental outcomes rather focussing on these direct costs. The AEMC's present approach of ignoring environmental externalities as outside the scope of the NEM is, therefore, also inefficient by design and its efforts towards more cost reflective components within the NEM's overall costs and benefits, such as with network tariffs, may actually be counterproductive and hence reducing the overall efficiency of the NEM.

## Question 3 – Open access arrangements

***Do stakeholders consider that an open access regime will continue to be appropriate in an environment of increasing uptake of distributed energy resources and more constraints on distribution networks? If not, what principles or considerations should be taken into account in determining whether a different access regime is more appropriate?***

As flagged by the Commission, access arrangements are extremely important for efficient DER investment and operation. We support the considered thinking that the Commission sets out in the Draft Report and the need for continued discussion regarding the relationship between investment certainty for consumers (which may be reduced under open access arrangements due to future export constraints) and efficient network investment, noting that this is a complex and nuanced relationship. Generally, we are supportive of maintaining open access arrangements. We consider open access to be beneficial because it ensures that incumbents and early movers do not capture an unfair advantage, at the expense of other consumers.

Furthermore, the point at which additional DER capacity may be denied access due to technical impacts is likely to be highly dependent on the specific location, time and operating conditions. Similarly to the transmission system, we therefore consider an operational decision signal to be more suitable than an investment decision signal. That is, rather than placing the requirement on NSPs to determine whether additional capacity should be allowed access at a specific location, provide signals with respect to operating behaviour (i.e. constrain DERs) and allow consumers to determine whether to take the risk of investing.

It is noted that constraints will need to be clear, open and easily understood in order for consumers to make efficient decisions; and also that, 'futures' contracts may be required as per our response to Question 2.

DER have the potential to provide network services, however this may be contingent on 'firm access' guaranteeing that the DER will be available when required. Whilst this presents a challenge, it is not considered insurmountable and should be the subject for further discussion. The AEMC is well placed to facilitate this discussion under the umbrella of the Distribution Market Model.

## Question 4 – Deletion of NER clause 6.1.4

***Is there support for the Commission's proposal that the deletion of clause 6.1.4 of the NER be explored?***

We do not support the deletion of clause 6.1.4, which prohibits the application of DUOS for the export of energy. However, we do support careful exploration of any costs imposed on the distribution network by DERs and the benefits which may be delivered. It is noted that the deletion of clause 6.1.4 would indicate a pre-disposition to the conclusion that DERs impose a net cost. This stance is pre-emptive and risks inefficient outcomes, such as not realising the value which DERs could otherwise provide.

Specifically, we do not support the deletion of clause 6.1.4 on the following grounds:

- As flagged by the Commission in section 5.4.2 of the Draft Report, the ESC found that:

  *"The value of the grid services that distributed generation can provide is too variable – between locations, across times and between years – to be well suited for remuneration via a broad-based tariff"*

  Similarly, the possible costs imposed on the network by DERs are likely to be highly variable and therefore traditional tariffs are likely to be too blunt an instrument for providing behavioural signals. Invariably, DNSPS will have competing as well as aligned interests with DER deployment in their network regions.
- There currently exists a significant lack of visibility regarding LV network operation and the 'actual' impacts of DERs (both beneficial and those which impose cost). Without improved understanding of impacts it is likely to prove inefficient for DNSPs to impose tariffs on export. Therefore we recommend increased reporting requirements regarding LV network operation. At a minimum, reporting of parameters relating to the technical impacts in Box 2.1 of the Draft Report should be considered.
- It may be possible to constrain export where it is not beneficial rather than imposing tariffs on export (which may also capture beneficial behaviours if applied bluntly). Such a technical solution is considered preferable since

negative impacts are likely to be highly dependent on local conditions, which could prove challenging to translate into clear and effective market signals. It is therefore recommended that the Commission consider 'fair' constraint methodologies, noting that previous work has been undertaken in this area.

Finally, it is important to note that the imposition of tariffs for export within the distribution network may significantly impact the commercial case for DERs which have already been installed, reducing consumer confidence. This is concerning for two key reasons; firstly the electricity system is undergoing substantial change and it is important to maintain social license throughout this transition. Secondly, reduced consumer confidence may result in reduced investment in DERs, even where benefits may exist, resulting in a lost opportunity for both the individual consumer and consumers as a whole.

# Question 5 – Australian Standards

***Are there any other aspects of the development of Australian standards that are relevant and should be considered?***

The Commission has flagged *AS 4777.2: 2015 Grid connection of energy systems via inverters* as a key standard for consideration. However, the issue of efficient market and regulatory arrangements for DER investment and operation is a far broader one than inverter connected distributed generation. As such, it is recommended that the AEMC considers the wider range of Australian Standards concerning distribution network performance and energy consumer equipment.

For example, the AEMC should be considering:

- *AS 61000.3.100-2011 Electromagnetic compatibility (EMC), Part 3.100: Limits – Steady state voltage limits in public electricity systems*

This standard is relevant because it sets out the voltage operational requirements for the LV network. Currently, voltage is measured on a 10 minute root mean square (r.m.s.) (refer to section 4.1 of the standard listed above), which may mask variability within a 10 minute interval. This is of concern because:

- The voltage conditions in the LV network may be substantially more variable than currently thought, therefore making the assessment of DER impacts on the distribution network challenging.
- Inverter connected DER settings may not align with the 10 minute r.m.s. measurement and subsequently DERs may be unfairly penalised by poor pre-existing voltage conditions. For instance, voltage conditions may cause DERs to regularly disconnect from the network, particularly if inverters respond to voltage conditions on a shorter time frame than the 10 minutes r.m.s.

## Question 6 – DER Connection Requirements

***Do stakeholders see value in the AEMC (or other party) reviewing the technical requirements that DNSPs apply to the connection of distributed energy resources?***

A review of the technical requirements that DNSPs apply to the connection of DERs is supported. The application of a consistent method across DNSPs is likely to increase clarity and efficiency regarding connection for both consumers and industry.