Consumer
Challenge
Panel

CCP14

Advice to the AER on the consultation paper

Assessing DER integration expenditure

AER Consumer Challenge Panel

Sub-Panel CCP14

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Confidentiality

To the best of our knowledge this advice neither presents any confidential information nor relies on confidential information for our comments.

1. The AER Consumer Challenge Panel

The Consumer Challenge Panel is established by the AER to provide advice on whether the network businesses regulatory proposals are in the long-term interest of consumers, and to advise on the effectiveness of the businesses' engagement activities in the development of their proposals.

Our advice to the AER is guided by the National Energy Objective (NEO), which is:

> "*to promote efficient investment in, and efficient operation and use of, energy services for the long-term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy*."

This advice has been prepared by CCP14 under its *Request for Information* from the AER. In order to provide the most complete and informed response, CCP14 has invited other members of the CCP, each of whom has had significant experience in recent distribution company regulatory resets, to contribute to this advice.

2. Introduction

The CCP is pleased that the AER has undertaken this 'lateral' review of assessing the expenditure requirements of electricity distributors to integrate Distributed Energy Resources (DER). We welcome the opportunity to provide this submission on the Consultation Paper.

From our observations of matters generating most conversation within consumer and stakeholder circles in the recent regulatory determinations for electricity distributors, this is a timely and important initiative by the AER. The impact and influence of DER and the related funding requirements prompted CCP10 in 2017 to highlight to the AER the emergence of the role of the Distribution System Operator and the renewed focus on low voltage distribution as an investment priority.

Underpinned by continued consumer investment in rooftop photovoltaic electricity generation (PV) – now embraced by over one-quarter of Australia's nine million homes and businesses – the electricity distributors' traditional views of the design, operation, augmentation, risk approach and financial return of their networks has been challenged. As signified by this consultation, DER is also forcing new thinking in the regulation of Australia's network businesses.

We support the matters raised and approach taken in the AER's consultation paper on *Assessing DER Integration Expenditure* and commend the AER on the preparation of such a comprehensive document. In this advice, we hope to provide the AER with a broad insight into the consumer and distributor issues that the changing energy landscape is presenting, in particular in the short to medium term.

This information is drawn largely from our first-hand interactions with electricity consumers and electricity distributors.

The rate of change leads to uncertainty

The rapid expansion in the customer uptake of DER is being driven by a few key factors. Falling costs of DER to consumers has made on-premise generation competitive in price with grid supplied energy. Many consumers also see DER as an opportunity to, on both a personal and a community level, contribute to a lower-carbon economy. Finally, some consumers see investment in DER as a step towards reducing their exposure to perceived future risks in grid security and price.

Generous government subsidies have created a 'hurry, don't miss out' approach for some consumers, as we have seen recently in Victoria.

While this is a great outcome for those consumers who can take advantage of the lower costs, it adds considerable uncertainty to DNSP network operation and investment as well as the operation of the wider market. Grid demand forecasts, on both a local and wider market scale, are difficult to address in a 5-year regulatory reset cycle. It is also evident that policy making has significantly lagged the development of DER technologies and consumer interest in the in the capacity of the market to respond meaningfully and effectively.

As the AER has noted, this is a very busy space in terms of regulation, research and policy development. This only adds to the environment of uncertainty. AEMO as the market operator is seeking ways of integration to meet the grid stability and reliability objectives. AEMC is developing market rules to address rapidly changing technology and market business models. ARENA is seeking to fund innovative projects to improve industry knowledge and learning.

State Governments see it as an area of promoting their climate priorities and popular subsidy policies. Changeability and low levels of industry consultation often feature in government policy related to DER, contributing to the swings in DER uptake, exacerbating the challenges for consumers, the related industries and networks alike. Almost daily media reporting of energy supply risks and environmental stewardship places energy issues, many directly related to DER, front-of-mind with consumers.

Unfortunately, market arrangements are unable to keep up with the uptake of DER and its influences on networks and consumers. The obstacles facing the efficient and timely implementation of Advanced Metering Infrastructure (AMI) are examples of this lagging regulatory response.

Our observations of the requirements of effective regulation in this environment of uncertainty are presented in section 5 - Embracing Uncertainty.

Ongoing Consumer and industry engagement are critical

Customer engagement, support and shared objectives are foundations of efficient DER investment. DER is generally an investment made to meet a perceived personal or business objective. Customers and networks must work in concert towards a mutually agreed capability. A strong utility-customer understanding and relationship is critical for the efficient application of DER.

This relationship must be clearly evident in any regulatory assessment of expenditure by networks to integrate DER.

Key messages

In this advice, we highlight the following key points:

1. DER involves accepting uncertainty. Ongoing, proactive engagement with consumer interests is crucial in progressing DER in the face of uncertainty and rapid change. Any assessment of prudent and efficient investment by distributors to integrate DER must include a robust consideration of how utilities have engaged with those with the greatest influence on the growth and application of DER – that is, consumers.
2. The AER's proposed definition of DER should be expanded to include a wide range of distributed generation and the demand response capability of customer-owned appliances and equipment.
3. Beyond the technical complexities of integrating DER, it is important that DNSPs are able to demonstrate their processes and strategies for ongoing engagement with all relevant stakeholders.
4. Forecasts of DER uptake and application need to be verified in the public arena by independent parties with a clear consideration of the NEO.

5. For this guideline, we support a more prescriptive approach, which may be relaxed as DER integration becomes better understood, tools mature, and the industry futures are clearer.
6. The effect of tariff reform will remain a key consideration when developing DER integration expenditures.
7. Expanding DER should not mean expanding cross-subsidies to those who are most able to install DER, particularly when those who are not benefitting from DER (and paying for the cross subsidy) are vulnerable customers, perhaps renters or unable to afford DER investments.
8. We advocate for the consideration of a totex approach to assessing DER integration expenditure.
9. Networks will need to be explicit in their interpretation of customers' expectations regarding DER application and feed-in capability, to help justify their proposed expenditure.
10. Guidance is needed to consider the benefit of DER-related investments to all consumers, not just those who are able to take advantage of DER directly.
11. Each DNSP should present a coherent and coordinated approach to DER integration across its expenditure plans, tariff strategy and demand management strategy in future regulatory proposals. We encourage each network business to prepare a clearly-articulated 'network future' that presents its forecasts, challenges, opportunities for innovation and risk assessments related to DER.
12. Access to dynamic, up-to-date data for networks and customers alike to respond efficiently and effectively to DER is critical. Action by the AER is needed to encourage the development of interchange standards and the efficient, low cost access to data.
13. Consumer protections, such as through ombudsman schemes, is essential to provide a basis for consumer trust in the uncertain energy environment.

DER presents a fast-moving target to which networks need to respond. Government policy announcements can initiate customer demands for DER in a very short time. Response to the consumer demand for DER can vary wildly in capability and quality. The relationship between policy development and the prudent, efficient and timely investment in networks is poorly understood.

We believe there needs to be a broader, industry wide, consideration of the impact of policy developments or changes – such as those affecting electric vehicles, advanced metering infrastructure, tariff reform, the Integrated System Plan (ISP) and Coordination of generation and transmission investment (COGATI). While ISP and COGATI are more relevant to TNSPs than DNSPs, there may be some consequences for the DNSPs in some areas.

3. What are Distributed Energy Resources (DER) ?

Important to this advice is the common understanding of the term *Distributed Energy Resources*. We suggest an expansion to the definition proposed in the Consultation Paper.

In the changing energy environment, we strongly believe that the world of DER extends beyond the uptake of rooftop solar and on-premise customer-owned battery storage, to include technologies such as automated demand response and demand levelling provided by electric water heating.

DER includes customers' demand response capability

As renewable energy forms a greater part of our energy mix, the intermittency and the relative lack of dispatchability makes the ability to 'match demand to the available generation' an integral requirement

of a modern energy system. Therefore, DER should be considered in a wider sense than just customer-owned electricity generation equipment and battery energy storage that is capable of parallel operation with the electricity network. Customer technology that permits a demand response called by network or market conditions in response to commercial or network signals also constitutes DER.

Essentially, we consider DER to be any customer-owned technology that:

- Operates in parallel with the network, capable of the feed-in of energy to the grid, and / or
- Allows the customer, whether through direct action or via an automated means, modify their electricity demand in near-real time.

Examples of DER include rooftop grid-connected PV, grid-connected battery storage, and off-peak controlled load (OPCL) water heating, air conditioning and pool filtration. In some cases, tariff structures are also a form of DER. This is discussed further in section 8.

The intent in this definition is not to complicate the thinking of DER itself, rather to recognise that so much of the new consumer technologies are interrelated, additive, and all subject to consumer response. In this advice, we ask the AER and utilities to consider DER in this wider sense, and demonstrate how proposed investment and benefits to consumers and their networks flow from a coordinated, holistic interpretation of DER.

DER includes residential, commercial and industrial customers

The interpretation and impact that DER can have on networks can vary by customer cohort, as well.

While the path to over two million roofs with PV has largely been in the residential sector, the majority (by capacity) of PV and DER uptake more recently has been in the small industrial and commercial customer sectors. These installations often have a different approach than households to issues such as participation in demand response and dynamic export limits, as well being larger and more likely to participate in demand response agreements or more bespoke connection agreements adapted to local network needs.

Any assessment framework by the AER will need to consider the fact that a 'one size fits all' approach to assessing a network's DER integration is unlikely to be efficient.

Network investments

Some utilities are considering DER to include 'network side' developments such as local energy storage. Utility-owned DER technology, particularly energy storage, is becoming a viable option in addressing network requirements, Other applications are testing new technical, commercial and market boundaries.

We commend these investigations, and acknowledge the innovative management frameworks set up by some utilities in ensuring consumer and stakeholder interests are represented in such projects. However, at this stage we do not consider utility-funded energy storage directly connected to the shared network as being within the scope of this advice.

4. Engagement and the Future Network Strategy

Noting the uncertainty associated with many aspects of implementation of DER, along with the rapid rate of change of DER technologies and rollout, it is critical that network businesses and the AER recognise that DER is fundamentally an issue of uncertainty. Strategies to deal with uncertainty are first and foremost ongoing engagement with consumers and other stakeholders.

This requires a process focus, perhaps even more than a technical focus.

It is critically important that DNSPs are able to demonstrate their processes and strategies for ongoing engagement with key consumer interests and other relevant stakeholders such as '4th party' providers associated with the implementation of DER-related strategies, as well as maintaining a shared understanding of emerging technologies and their possible application. This process needs to be adequately resourced and ongoing so that is a dialogue.

Engagement must be genuine two-way processes are not consigned to the 'inform' and 'consult' end of the IAP2 public participation spectrum.

We also note that responding to rapid change and uncertainty means that some decisions, in hindsight, will not have been the best decisions, or to be blunt, mistakes we made. A process of active engagement must include acceptance of mistakes being made which need to be embraced and the learning shared. We recognise that this is a challenge for risk averse network businesses as well as for regulators. As long as the application of DER strategies is understood as a shared responsibility - shared by consumers, DNSP's, retailers, DER providers and regulators - then the path forward will be constructive.

Therefore, we see a priority for networks to present a very clear 'Networks Strategy', with the audience being regulators, policy makers, consumers and other stakeholders. The strategy would consider:

a. The high-level assumptions and forecasts that underpin the planning and growth expectations. These assumptions and inputs need to be made public and validated by independent, customer-representative external sources.

b. The research that demonstrates how consumers are likely to use the DER in response to the signals provided by the various market entities and customer needs to be based in strong consumer engagement and/or research.

c. How the networks expect to address the impact of the DER growth requires a high degree of innovation, risk assessment and appreciation of the potential high rate of change of technology and customer expectations.

d. Options considered will include technical, commercial and social influences.

e. The DER integration strategy will need to correlate with the distributor's strategy for capital investment for augmentation, replacement and reliability, consumer engagement and corporate messaging, as well as the objectives of the tariff structure strategy.

f. As much as possible, costs and sensitivities need to be detailed

We believe the requirement for networks to produce a DER strategy is a necessary adjunct to the expenditure guideline.

5. Embracing Uncertainty

We suggest that there are four important, non-traditional implications for policy, regulation and practice associated with the high levels of uncertainty provided by the current, exciting and unpredictable opportunities provided by DER.

Acknowledge the environment of uncertainty.

In an industry that has always sought certainty, accepting the inevitability of uncertainty in DER matters may be challenging, but must occur. All parties need to be able to accept and to state publicly that they don't always know the answer to an existing or emerging dilemma. While embracing uncertainty is difficult, it will significantly build the trust of consumers if honestly communicated, with discussion about possible solutions and invitation to engage.

Ongoing, shared problem solving with consumers and other stakeholders.

This means "involve" and "Collaborate" processes from the IAP2 public participation spectrum as standard consumer engagement practice, not "inform" and "consult." We note that the AEMC is currently seeking stakeholder advice on draft rules to implement regulatory sandbox arrangements in both electricity and gas markets.

The AEMC summarises regulatory sandboxes as "*a regulatory sandbox is a framework within which participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.*

Regulatory sandbox arrangements will make it easier for businesses to develop and trial innovative approaches to providing energy services to consumers."

Regulatory sandboxes are one set of processes to deal with uncertainty and to involve consumers in shared solution seeking with DER an ideal set of topics for "regulatory sandboxes".

Acceptance and transparency about 'failure'.

Regulatory practice in global as well as Australian energy markets have tended to operate from the acceptance that there is a known, ex ante, best (optimal) outcome. The reality of DER applications is that some regulatory, policy and practice solutions will be applied that in review, are wrong. There needs to be acceptance of 'failure' of this type and clear process to identify failures and to transparently share the learning from 'failures'.

Dynamic, not static systems.

In line with the comments above, we note that DER technologies, solutions, regulation, policy and consumer preferences will all interact with each other and will all change over coming years.

DER systems are dynamic, while past models of energy markets have generally worked as static models with fixed engineering approaches, known standards and consequently predictability that can be enshrined in standards, policy and regulation. Indeed, the National Electricity Objective (the NEO) is sometimes interpreted as assuming that a generally static, optimal future best interest of consumers is known or ought to be done.

This is not the case for dynamic systems. DER regulation will need to change as we learn more. We acknowledge that the AER must 'walk a fine line' between the need to embrace a dynamic and changing environment, and the networks' desire for predictability and stability in their investments and operations.

6. DER in the community

Ultimately, the objective of this paper is to develop further the framework in which consumers and other stakeholders can have confidence that electricity distributors continue to make prudent and efficient decisions in the operation and development of power networks in the changing energy environment.

Changing network priorities

In framing regulatory proposals that respond to the challenges and opportunities of DER, we have observed that utilities are required to consider:

a. A greater diversity in consumers' expectations of the services to be facilitated by the distributor, from basic, affordable electricity supply, to the role of a relatively passive 'prosumer', to the ability to participate in energy trading and demand response markets.

b. A wider range of electricity demand patterns, leading to localised, un-dispatched, variable energy feed-in, falling network utilisation and an indifferent impact on peak demand. The traditional design criterion of After Diversity Maximum Demand (ADMD) is fast becoming superseded, leading to the need for new approaches to network design as well as voltage and network capacity management.

c. On a wider scale, the uptake of DER is challenging network operation systems, requiring reviews of protection systems and raising concerns about how to manage 'minimum load' periods.

d. The rise of market entities 'between' the distributor and the customer, including retailers, aggregators, Virtual Power Plant (VPP) operators and DER system integrators. These '4th parties' have operational and commercial objectives that are not necessarily consistent with those of the network operator. Market and regulatory frameworks are not developing at the same rate, giving rise to operational uncertainties and ad-hoc performance management arrangements.

e. Rapid and changeable consumer acceptance and application of DER, as a result of:

- the rapid rate of change in DER technologies,
- falling costs of DER relative to grid energy,
- changing government policies, short-term reactions to incentives and fast uptake of offers, and
- a dynamic and responsive installation industry.

Changing customer priorities

Consumers, too, are adjusting to the growth of DER in the new energy environment.

f. Commercially, the momentum that exists regarding the reliance on volume-based tariffs means that distribution tariffs, especially for the majority of consumers who cannot afford to engage in the DER environment, such as renters, people living in apartments and aged-case villages, remain exposed to bill risks under a revenue-capped regulatory framework.

g. Research continues to show that the uptake of DER, in particular solar PV generation, will continue as the price relationship between grid energy and the levelised cost of energy from rooftop or local generation falls. Consumers have little regard to the challenges created on networks by the expansion of PV, other than the narrow view of connection complexities, export limitation and tariff changes.

Expectations from consumers have been drawn from most distributors having explored the issue of DER growth. From these community forums, we believe that consumers:

1. Expect that utilities will continue a level of investment to support an energy future that includes a greater proportion of renewable sources. We have observed a level of community support for investment in the greater access to renewable energy, even from consumers who are unlikely to invest in DER or embedded generation themselves.
2. Expect utilities to invest in networks to support emerging consumer expectations, such as a right to connect embedded generation or energy storage, or, in some cases, facilitate per-to-peer energy trading or 'local energy sharing'.
3. Will participate in demand response, energy feed-in and respond to tariff signals so long as the tools and commercial incentives exist.

7. DER - what's in it for consumers ?

The application of DER, in particular rooftop PV, started life as a powerful bill-reduction opportunity and vehicle for relative energy independence. While this approach remains the predominant customer benefit of DER, more recent customer surveys are noting a heightened awareness of a community asset that supports a higher degree of use of energy from sustainable sources, as well as an opportunity to capitalise on new market opportunities such as local energy trading and demand response.

The initial focus on residential PV has now expanded to much larger commercial and industrial applications. DER is presenting opportunities for consumers to respond meaningfully to more innovative demand and time-varying tariffs.

A critical component for assessing DER expenditure by regulated networks is to define and apply a recognised set of benefits for all consumers in their investment analysis.

The equity imperative

Consumer sentiment regarding DER and the changes to network costs and tariffs are very hard to track. There is a significant body of evidence that demonstrates that the large majority of customers who have invested in DER do so in response to high and uncertain electricity prices – in essence to empower themselves to address the perceived negativities of grid energy, particular prices. Others note the opportunities of peer-to-peer energy trading, selling 'spare' energy to the market and the like, but the overwhelming evidence is that customers are essentially seeking to reduce their electricity bill.

Alongside this approach, the social accountability of contributing to a low-carbon future is common.

The limited capacity to access the benefits of DER by many consumer groups is often understated, with the main DER response focus being directed towards 'prosumers' - the approximately 30 to 40% of customers who can afford to install rooftop PV and consider being part of a VPP or even buy a battery.

We suggested a similar proportion of households, up to 40%, have very limited capacity to engage with DER because they are renters, particularly in the private sector rental market where rooftop PV installation rates are well below 5% of dwellings in jurisdictions with over 30% PV penetration rates. The South Australian government's battery subsidy program has recently reported that only 11 rental properties are part of their battery scheme. Households living in apartments, with south facing properties or other low solar exposure are also hampered in their ability to participate in DER, particularly applying rooftop PV, the most common current consumer form of DER engagement.

The South Australian government has recognised the limits of DER access for some households in its public housing strategy, where a rollout of rooftop PV on public housing properties is associated with a VPP, with the intent that benefits are shared by all public housing tenants, not just those with rooms that are suitable.

Notwithstanding the many positive attempts to enhance equity through DER, there is the risk that some forms of implementation of DER strategies can benefit homeowners and higher income people, and adversely impact on low income people who can't afford to participate. An aspect of this was documented some years ago in the "death spiral" paper by Paul Simshauser and Tim Nelson, which highlighted the risk of higher income people being able to go "off grid" or at least reduce their reliance on electricity network. With volumetric tariffs this would increase prices for remaining grid customers under revenue cap regulation, decreasing their capacity to afford investing in distributed generation.

Equity is a difficult concept to define as it is often in the eye of the beholder.

> "As a renter I am cross-subsidising those who have roof-top PV" or

> "As an owner of roof-top PV I am not being cross-subsidised because I am saving the network $ and in any case I am increasing the availability of low carbon power to the grid that has a social benefit".

Many reports and observations of community engagement regarding DER highlight the desire for social energy equity – that is, the ability to share excess energy with those around. The conversation about the financial returns of that shared energy remains varied. However, the general concept of unconstrained feed-in is a common point of support in consumer engagement. For example, as part of its 2020-25 reset engagement, SA Power Networks (SAPN) undertook extensive consumer engagement on this issue, looking at three options:

- Restricted or constrained export capability through fixed export limits specified in a connection agreement,
- Unconstrained feed in, allowing maximum approved or contracted energy export at any time, and
- Dynamic management and curtailment, where export can be constrained by the network business through a control system at times of network congestion.

SAPN concluded that consumers preferred the dynamic management approach, and has gained approval in the AER's Draft Decision for expenditure to obtain better data on how the network's capacity to take additional exports varies by location.

Wholesale cost benefits for all consumers

A very important consideration in the broader cost-benefit assessment of DER-related investments is the benefit of the investment to all consumers, not just those who partake in DER investment. To date, the predominant approaches to such benefit analysis have been:

1. The deferral of network augmentation capital expenditure through reduced demand peaks or a reduction in the total load-at-risk at times when network security is compromised, and
2. The reduction of the wholesale price of energy as low cost excess rooftop PV is fed into the network, offsetting more expensive forms of generated energy.

In our opinion, there is little evidence that either of these benefits has become obvious to consumers who focus on the reduction in their individual bill from lower grid consumption plus feed-in tariff. There is a range of academic studies purporting to show the impact of renewables (small and large scale) on wholesale prices. We are yet to see a noticeable impact on reducing grid investment, which is not surprising given its long asset life. Capital investment in networks appears to be limited more by energy efficiency through the adoption of modern appliances. Networks generally have highlighted that DER has had a very limited impact on peak demand. Even the battery trials in South Australia suggest that VPPs are in fact adding to peak demand limitations rather than alleviating them.

Proposals to invest in significant new transmission assets will also have the impact of raising network prices. Firming investment by AEMO is significant. For example, the increased costs of RERT in recent years can be due to increased distributed solar PV.

Therefore, the way networks assess benefits to all consumers from DER integration expenditure should be the subject of AER scrutiny.

Valuing DER to the whole community

Integral to the DER investment case by utilities has been the requirement to develop 'hosting capacity'. In this investment case, the value of the expenditure (and consequent increase in distribution costs) is contrasted against the value to the wider community of this investment. The benefit case tends to have two aspects.

a. Reflecting the community interest and commitment to encourage an energy future that includes a greater share of renewable energy and wider customer choice regarding energy matters, and

b. A return to all consumers through lower distribution costs and a reduction in the wholesale energy component of the total electricity bill.

Reports by utilities have been presented as part of business cases in trying to quantify this value to all consumers; generally (in our opinion) fairly unsuccessfully. As part of this AER consideration, we ask the AER to consider how utilities can state the 'benefits side' of the DER hosting capacity business cases, if for no other reason than to establish a level of consistency and clarity for consumers when considering these investments.

Applying DER solutions to remote and edge of grid communities provides ever more cost-effective options to significantly reduce the reliability of supply and reduce costs for people who have not always been well served by "the grid".

Is feed-in a right?

The hosting capacity and equitable access to the network is a cornerstone of the network's approach to DER integration.

Unclear in the planning is a firm position on the role of energy feed-in in the market. When lucrative feed-in incentives applied some years ago, the payment received from excess energy fed into the network played a major part in the customer's investment decision. Networks struggled to assess and approve feed-in arrangements in connection agreements.

Nowadays, with falling DER prices and a greater understanding of self-consumption technologies, far fewer consumers are reliant on feed-in payments to contribute to the positive business case of their DER investment. However, this is unlikely to remain the case, as incentives for energy feed-in in the form of peer-to-peer trading and the environmental aspect of renewable energy replacing 'less green' sources gain momentum. This will reignite the case for 'feed-in rights'.

Networks will need to be explicit in their interpretation of customers' expectations regarding hosting capacity and feed-in capability, including how that position was determined and the risks associated from changes in external influences or technologies that may impact their assumptions.

Some parts of the network may have significant excess capacity that allows more flexibility in export limits. Other parts may have no spare capacity. Again, we get into how 'equity' is defined. Is it 'inequitable' to restrict exports of the latter location and not the former location? Are customers in the former locations willing to pay higher network charges to allow customers in the latter locations to have the same export rights as they do? These are discussions networks need to have with their customers.

The maturing role of DER in the community

Initially, customers invested in DER, primarily rooftop PV and before then off-peak load control facilities, to realise immediate and accessible commercial benefit in the form of lower electricity bills.

Over time, we have observed the community response to DER maturing. The prime incentive for the investment in DER remains to reduce energy bills. However, research suggests that the investments are taking a greater role in meeting expectations of a more sustainable energy future, and, hopefully, lower energy prices for all. With the removal of the generous feed-in tariffs, the integration of DER has become a wider consideration of self-consumption opportunities and engagement in demand response. Therefore, we see greater consumer acceptance that DER is part of a 'bigger picture'. Similarly, the investment case for consumers is less reliant on large feed-in tariffs.

There is a greater acceptance now of the factors that are becoming necessary for grid stability, broad voltage management, and the capability to respond to contingency events. We see flexible export limits for DER becoming an accepted trade-off to fixed export limits, and the investment by networks in flexible export limit management as necessary over time. On the network side, we see investment in advanced protection schemes, such as the proposed major revision of the SA Underfrequency Load Shedding (UFLS) system as inevitable. The key issue will be the timing and prudent investment related to this initiative.

The commercial and technical agreements remain under development, and should be designed and implemented with consumer consultation.

Customers choosing to exit the grid

DER is providing an opportunity for customers to exit, or at least significantly reduce their reliance on, the network. For those at the 'edge of the grid', poor reliability or high network charges can encourage those customers to seek independent energy supplies from renewable sources in conjunction with storage and/or standby generation. This is a risk in states such as Queensland where the tariffs associated with irrigation and pump sites are making the transition to alternative energy sources viable.

In addition, some customers are changing their relationship with the network to one of 'standby supply'. An example is the water utilities in central Victoria, where solar PV presents a cost-effective source of energy for water pumping, and the connection to the network remains only as a source of energy in times where the renewable source is unavailable or insufficient.

In these circumstances, network assets can become stranded or heavily underutilised. The cost of the removal or ongoing maintenance of these assets is absorbed under our regulatory framework by other customers. Consideration of the costs and benefits of integrating DER must include the role of the network should it become very poorly utilised in the short, medium or longer term.

8. Tariffs and DER

The AER correctly notes that 'The effect of tariff reform will remain a key consideration when developing DER integration expenditures and this should be factored into a networks business case for DER-related expenditure.' [1]

This is a key issue. As the establishment and application of DER is determined by consumers, other consumer sentiments and responses to energy use must also be considered. We are only aware of a few distributors that have meaningfully and intentionally integrated their tariff structures and DER explicitly.

Networks must be able to show the integration of all consumer influences – DER impact, tariff structures and connection incentives – as part of any DER expenditure proposal.

The consultation paper (p12) states "network tariff reform is key to making energy markets work better for consumers".

We do not think the AER should approve DER integration expenditure, both capital and operating requirements, in the absence of comprehensive, delivered tariff reform. We recognise that such reform may take place on a different timeframe as compared to the DER uptake and hence investment requirement, but there should be a clear commitment to tariff reform shown by significant progress in the initial 5-year reset period in which the expenditure occurs.

[1] Consultation paper section 5.2.2

9. The dynamic nature of government policies

One significant challenge in assessing DER integration expenditure is the assessment of risks that the investment will turn out, even in the short term, to be excessive or insufficient. A predominant variable in the attempt to forecast DER growth is the political influence on subsidies, feed-in arrangements and the form of DER. We have seen significant, arguably well-intentioned, change in these matters across various jurisdictions.

Often, such policy is implemented in short time frames, with little preliminary engagement with stakeholders, and can lead to wild market variations and sometimes unrealistic customer expectations.

Some networks have good working relationships with governments to the point where policy can be informed to minimise the need for additional network investment, or improve the utilisation of existing assets. Networks need to demonstrate how they are working to engage governments and policy makers, either directly or via consumer and stakeholder channels, to provide information, leadership and effective responses to government policy decisions regarding DER.

Similarly, the world of electric vehicles is likely to receive the same treatment from both federal and jurisdictional governments. Therefore, we can expect a similar set of investment proposals soon from distributors that are also likely to be subject to political influence, variable uptake and implementation leading to network limitations.

As part of this work, we encourage the AER to consider developing part of the DER guideline to cover how they will assess capital proposals designed to facilitate electric vehicle uptake.

10. Networks' responses to DER

The rapid uptake of DER by consumers has many of the hallmarks of the significant growth in peak demand around 20 years ago, when consumer preferences driven by low cost appliances (mainly air conditioners) presented a new 'unknown territory' for distributors. In response to that rapid consumer-driven change, we saw major revisions of network security policy leading to unprecedented level of network investment, with adverse price impacts that we still see decades later.

We can only trust that the response to this 'disruption' does not lead to similar outcomes, especially when the initiating events – PV, batteries, loads from electric vehicles and augmented demand response – remain dynamic and so sensitive to external policies and localised network conditions.

We recognise that networks are approaching their expenditure to meet three objectives.

1. Networks are trying to 'rediscover' their low voltage systems through better monitoring, data gathering and modelling. This information will then inform future decisions.
2. To address emerging localised constraints through network augmentation, connection modifications and control system innovations
3. Reduce wider network security risks arising from minimum load impacts, underfrequency load shedding systems and protection limitations.

We expect networks to continue to increase their investment in market intelligence and the engagement of industry, stakeholders, '4th parties' and of course consumers.

10.1 The nature of the networks' response to DER

Unlike the peak demand risks, we have observed four somewhat unique factors in the way networks are responding to the DER challenge.

1. A risk-averse, 'no regrets' approach to planning and investment

The parameters that define DER are variable, and in some ways 'out of networks' control'. Government subsidies, falling equipment prices, even media reports on electricity grid security all influence customer investment in DER with very short response time cycles. Even so, this should not preclude networks from taking an influential and leading position on such issues wherever possible.

We have observed networks tending to take a very risk-averse view in their future planning and network responses, with language such as 'least regrets investment' becoming commonplace. It becomes difficult to extrapolate traditional investment planning criteria – load growth rate, demand forecasts, network utilisation and available capacity – when so many of these parameters are subject to variables that are not only outside a network's control, but being 'behind-the-meter' are often outside their field of view.

2. Connecting DER does not present an economic return to network businesses

DER does not tend to lead to significant returns to networks and their shareholders. In fact, adopting to the connection process and network impact of DER is in some ways seen by networks as detrimental to business efficiency and optimal network utilisation. Networks are accustomed to customer energy trends that lead to more network assets, resulting in greater economic returns through growth in the regulated asset base. DER growth is different. The bulk of investment is on the customer side of the meter, and it is the customer who has great interest in the return on their investment. For networks, DER is not resulting in significant investment in new power lines, new sub-transmission assets, or new zone substations.

This is a nuanced issue. Certainly, the landscape is changing, but widely we still see proscriptive connection agreements, conservative feed-in limitations, and many examples of frustration for applicants of DER from delays in connection applications. We believe that this is in part because networks see little advantage – certainly commercially or technically – in DER, so there is little incentive for networks to be at the forefront of innovation, challenging technical paradigms, or aggressively seeking proactive customer engagement.

DER also impacts networks through reduced recoveries. As customers choose to generate their own kilowatt hours, energy carried through the grid is changing in both magnitude and load pattern. Many large customers, for instance warehousing, schools and utilities, who are significant contributors to the networks' bottom line, are seeking cheaper energy alternatives through DER. With network cost recovery still very dependent on volumetric tariffs, redistribution of costs under the revenue cap is occurring.

Of course, the revenue cap regime under which networks operate means that those DNSPs are largely ambivalent to changes in network utilisation and overall cost recovery at least in the short term. In the longer-term, networks are moving towards demand and capacity tariffs, but again 'equity' issues arise as consumers are concerned about the impacts. In some cases, networks have not articulated what problem these tariff structures are intending to address, or how these tariff structures, as against other tariff structures that customers would find easier to understand and respond to, provide the best solution to the unexplained problems that the network faces.

3. The desire for more data

Low voltage distribution systems, the prime connection point for DER, are probably the most extensive yet least understood part of the electricity distribution network. We acknowledge and support the need for networks to understand better the performance and operating parameters of the low voltage network. Some utilities have taken steps in this area, with Energex and some other distributors using smart metering

at the low-voltage terminals of distribution transformers, and the visibility of the technical parameters of the customer connection provided by the AMI rollout in Victoria.

Other utilities have a strong case for better LV visibility. In so doing, we implore consideration of the 'bigger picture'. There is a lot going on at the customer interface, including tariff reform to interval and demand-related tariffs, continued consideration of compensating customers for feed-in energy, monitoring neutral conductor integrity, and as a gateway for load control and related demand response. In considering the need for better data on the LV network, consumers are keen to draw maximum value from investments, often with a wider scope than that of the network business itself.

It is recognised that several regulatory and technical hurdles exist in facilitating a more holistic outcome. However, we continue to encourage all parties to seek the most cost-effective outcome for consumers, even if it presents a few compromises for the individual market participants involved.

4. The orchestration imperative

On a macro level, the growth of DER is presenting wider network impacts. This is highlighted by the imperative for networks to consider wider operational parameters, culminating with the need to coordinate with the market operator on new issues, including:

- Minimum demand considerations – such as AEMO's forecasts that in a few years' time the output of solar PV (excluding large scale renewables) will be sufficient to meet minimum demand in South Australia,
- Demand response to address utility generating intermittency and dispatchability (or lack thereof),
- Network emergency response, such as under-frequency load shedding, and
- Network protection with low fault levels.

An outcome of such matters is the need to introduce a form of control or dispatch framework to meet these needs as well as allow more equitable access to local networks. We are seeing action on this front, from the SAPN-led DER Working Group across utilities to consider standards for the dispatch of small embedded generators, to improved network protection, to the ENA – AEMO – CSIRO initiatives of open networks.

It is clear that networks will need funding to participate in, and ultimately comply with, the orchestration imperative.

Efficient investment in the capability to facilitate DER by networks, whether it be capital investment or ongoing operating expenditure, is a difficult area for consumers to consider, for reasons including:

i. Under the banner of 'increasing hosting capacity', networks generally propose new investments, often for long-lived assets that will feature for some time in the regulated asset base, despite the falling network utilisation and relatively stable peak demand. This counter-intuitive response also fails to support consumers' expectations that greater energy independence introduced by DER means networks have a 'lighter' role to play in the future.

ii. Addressing local voltage issues have wide range of solutions that span technical constraints, network augmentation and customer responses. Networks tend to polarise to the augmentation solution, as it is in their long-term commercial interests to do so and is seen as 'less risky' that implementing non-network solutions, most of which rely on predictable customer energy use behaviour or new forms of contractual connection agreements.

iii. Beyond the important overall approach to a more sustainable energy future, tangible economic returns to customers - especially for those without access to DER - are poorly defined and hard to see. Opportunities for network businesses to capitalise on Australia's

remarkable DER, such as reduced network augmentation and a 'thinner' network generally, remain largely undelivered. We do acknowledge the work by some utilities in this area, such as remote area isolated power supplies.

10.2 What's in it for networks ?

Key to this change is to encourage and reward networks to embrace change. On one level, networks are enthusiastically becoming involved in trials and projects regarding DER, both behind and on the lines-side of the meter. Networks in Australia see change as necessary and inevitable.

The fundamentals to which networks and retailers operate – seeking stable returns from large asset investments or minimising the cost-to serve – remain. Without deep-seated regulatory and market change such as introducing revenue opportunities for 'spare' network capacity, or retailer incentives to efficiently undertake local energy trading, the paradigms prevalent in existing utilities and markets will prove hard to change. For Distribution System Operators (DSOs), the growth in the penetration of rooftop solar PV and DER has not yet delivered opportunities to significantly reduce network augmentation costs and deliver operational productivity. Peak demand, occurring mainly in the late afternoon and evening, is not largely influenced by the existence of solar PV, and is not mitigated by household energy storage under current operating practice. Demand may have been limited somewhat by improved appliance efficiency and the price response by consumers, but it remains a driver of network capital investment. Minimum demand levels are also gaining notoriety for complicating network voltage and protection stability. The duck curve – including the 'belly of the duck' - has become a significant factor in the technical and commercial operation of networks deep into the local supply system.

1. **Addressing falling network utilisation**

Under Australia's revenue-cap regulatory framework, little commercial incentive exists for network owners to improve asset utilization (load) factors, as their revenue is set largely by asset values, not by the amount of energy passing through the wires. This is a core issue for many utilities worldwide. Despite the application of incentive-based regulation, risk is not clearly rewarded, and new revenue streams to encourage the transport of energy by existing assets are very limited. Until networks shareholders see a commercial return from connecting embedded generation and fostering customer behind-the-meter resources, the new energy future may not arrive as quickly and efficiently as many consumers would hope.

2. **Resilience**

Resilience is an emerging area where DER can play a significant role. As local energy generation includes a degree of 'dispatchability', storage of available energy in the form of batteries becomes more cost effective, control systems for more traditional generators mature and demand response tools develop, DER can be integrated as an efficient mechanism to improve network resilience in local areas. Such an approach is valid for households, businesses and local communities.

In assessing DER integration expenditure, the community benefits in recognising network resilience will require consideration. But for this to occur there will need to be considerable changes in market rules to recognise new business models. It is one thing for DER to be faced with the efficient network costs of their participation in the market. They also need to be able to source revenue streams for the provision of those DER services.

3. **Jurisdictional emission reduction targets**

We expect that there is a high chance that legislators may continue to seek emission reductions through many avenues, including the electricity industry. DNSPs mush have regard to any legislated jurisdictional emission reduction targets as these may increasingly have an impact on their DER strategy and expenditure.

4. **Open networks and the transition to a Distribution System Operator (DSO)**

ENA and AEMO have proposed a few options as to how the coordination and operation of DER may be implemented. We believe the establishment of a DER investment guideline will need some level of resolution on the function of the open network framework.

5. **Stranded Asset Risk**

In our current regulatory framework, it is consumers who bear the risk of stranded assets. Given the pace of technological change that bringing the greater accessibility and rapid fall in the price of DER, the same change suggests alternatives to traditional networks will eventually become more viable. The emergence of local microgrids and stand-alone remote power supplies are examples of this development.

Therefore, great caution is needed in approving the investment in assets with lives greater than, say, 20 years. We see a parallel argument in the investment in transmission assets – an issue that is being actively considered in other forums.

11. Our expectation of outcomes from this DER review

11.1 A total cost (totex) approach is needed

Given the flexibility needed in formulating and implementing a DER strategy and expenditure proposal, we recognise that costs may not only include capital expenditure and operating expenses, the approach taken by networks may require a level of fluidity between these two funding mechanisms.

Therefore, we advocate for the consideration of a totex approach to assessing DER integration expenditure.

11.2 Data for consumers, networks and other market entities

Two issues are often quoted by networks regarding the information needed to understand the real-time performance of their deep networks and to apply any controls based on dynamic network modelling.

Network businesses should be encouraged to exploit existing data holdings to the fullest extent possible.

We see two advantages in doing so.

First, consumers are at risk paying twice for the industry to collect and analyse their data – to the retailer or meter provider for data services and to the network for purchasing the data from retailers and metering coordinators or developing alternative data collection systems.

This is an unreasonable impost on consumers.

Second, there are advantages in establishing data sources that provide benefits beyond just that to the network operator. AMI is a prime example, where the information presents additional opportunities for consumers to embrace new and more appropriate energy tariffs and provide consumption data to consumers to better manage their energy use. While the solution may not be ideal in form and timeliness for any one market participant, overall the advantages to consumers suggests a compromise solution may be most efficient.

The AER, network businesses and consumers should all be pressing regulators, including the AEMC, to ensure this data is available to networks free of charge. Also, the data availability needs to incorporate a data interchange standard, encompassing standard formats, accuracy, completeness and timeliness.

Some networks are exploring the development of network data models to circumvent the need to access data from external sources. The case for developing this capability may certainly be sound. However, realistic and genuine approaches to source data from existing sources must form part of the investment business case.

11.3 A prescriptive approach

In this guideline, we support the AER beginning with a more prescriptive approach to the information a network is to provide as part of its revenue proposal. This prescriptive approach would be in place for one complete revenue cycle – until the completion of the NSW/Tasmania/NT 2024-29 reset. Then it would be reviewed. As we have seen in recent resets, it is very difficult for consumer advocates – and we believe, the AER – to have a clear view of DER expenditure. Prescription provides a comparable data base across networks that can have benefits in future benchmarking Given the incentives for networks to take a risk-adverse approach to this investment, we believe that explicit requirements in the way networks present their proposals is needed.

The recurrent / non-recurrent approach taken for ICT does not work well in this rapidly-changing environment.

11.4 The form of a proposal for DER integration

The AER has highlighted the intention that DER integration expenditure supports better outcomes for consumers by improving the way networks forecast and assess DER expenditure, and to seek balance between the costs, benefits and risks inherent in such investment.

While supporting these overall reasons, we would also propose important outcomes of this review for consumers include:

1. Encouraging networks to prepare a clearly-articulated 'networks future' that presents the distributors' forecasts, challenges, opportunities for innovation and risk assessments related to DER. Ideally, the hallmarks of a network futures strategy would:
    a) Be developed with a high level of involvement, preferably collaboration, with stakeholders including representatives from a cross-section of customer cohorts, government, DER industry and related policy influencers; and
    b) Consider the wider implications and relationships with distributors' accountabilities beyond the technical needs, including tariff responses, demand response, consumer engagement, innovative approaches and the risk response through challenging existing commercial and technical paradigms.
2. Guidance for networks to present their DER plans – both capital and operating costs – in a form that:
    a) allows the AER to, as much as possible, meaningfully consider the prudency and efficiency of the investments to a level of maturity that already exists for the operating expenditure and capital investment in 'traditional' asset classes; and
    b) does this in a manner that allows consumer groups to understand the purpose of the investment, the options considered, and the impact on energy prices (both short and long-term) and network capability.
    c) presents the perceived benefit streams of such investment to both owners of DER and other consumers as coherently and clearly as possible.
    d) Clearly explains the forecasts, risk assessments and counterfactual arguments that underpin any 'least regrets' approach that the utility may take.
3. AER assessments in the future to view DER investment as an integral part of wider capital and operating requirements. The DER assessment should be placed against proposed augmentation planning, opportunities for innovative responses to network reliability and maintenance risks, and tariff development.

4. The communication and control systems associated with DER integration will naturally fall under the cybersecurity risk profile related to critical infrastructure, as well as raise risks of customer data privacy and appliance performance.

   It is inevitable that expenditure related to cybersecurity will be incurred. Such investment should be identified in the DER strategy (to the extent reasonably possible) and considered a DER cost and included in any DER cost/benefit analysis.

12. Response to questions

Question (i) – Are our assessment techniques outlined in our Expenditure Forecast Assessment Guideline (the EFA Guideline) sufficient to assess DER integration expenditure?

We note and support the AER's assessment proposal (see consultation paper p5-15) and support the establishment of a separate DER integration expenditure guidance paper.

The issue is that the scope of the problem definition is wider than that implied in the consultation document. While the key issues of voltage non-compliances and hosting capacity remain, we will look for significant work by the utility to consider a wide range of options and influences that both support the forecasting and expand the range of reasonable and practical options to address the need.

With respect to the Expenditure Forecast Assessment Guideline, it is likely that the mix of viable options to address DER growth with span a range of solutions, including capital investment in network and technical capability, operating costs in the form of third-party arrangements, and even options related to tariff structure. Therefore, the approach to apply tests for capital efficiency or trends in operating costs as framed in the guideline may not be ideal in assessing DER impacts and needs.

In addition, there are few benchmarks or trend analyses that would apply, for the next few years at least. The predictive modelling aspect of the assessment guideline will be very important, including the features discussed in section 4 above. Similarly, the broad and dynamic range of DER approaches from governments will challenge the guideline's approach through benchmarking. Community sentiment to decarbonisation may also require a slightly different approach to cost-benefit modelling as well.

In summary, the guideline may be a useful approach to assessing DER integration, but the application will require a level of innovation and flexibility to address:

- Few established benchmarks and trends on which to rely
- The capital / operating trade-offs and mix in addressing solutions
- A high importance on consumer engagement, sentiment and feedback
- Addressing equity across consumer cohorts
- A focus on risk assessment and a 'least regrets' approach if prudent

Question (ii) – What form of guidance should we include to clarify how our assessment techniques apply to DER integration expenditure? For example, should we update the EFA Guideline to be more prescriptive, or only include principles to allow for greater flexibility in our assessment and information requirements as DER integration matures?

Ultimately, integrating customer DER into networks will become 'business as usual' – at least to the extent that the changing customer and technical landscape will allow. Therefore, it is reasonable that any guidance will come under the EFA Guideline.

We do recognise that a more general *principal-based approach* will be more effective that prescriptive rules.

That being said, given the highly dynamic a nature of DER development and the range of external influences that can impact DER uptake, it is important that utilities explicitly include key elements in their proposals would be critical in gaining consumer support for any investment or operating expenditure. Suggestions as to the form and content of any guidance is discussed in later responses.

Therefore, we support a more prescriptive approach in guiding distributors in their funding proposals, that includes:

- A holistic assessment that includes DER impacts on ICT, augmentation, replacement and reliability funding needs.
- Clear direction regarding the relationship between DER integration and tariff strategy
- A strong focus on ongoing engagement with customers, industry and policy makers
- Seeking common approaches to addressing challenges

These issues are discussed in more detail in the sections above. We believe a more prescriptive approach can provide incentives for distributors to provide the right level of detail and justifications in their proposals, while leaving open the form of solutions, risk approach and pursuit of efficiency.

The EFA guideline could be updated to recognise a range of capital / operating / tariff responses, as well as adopt to the 'no regrets' form of investment decision that some utilities are highlighting as the best way of approaching investment decisions in a variable and dynamic environment.

Adapting the role of the DMIS

The role of the Demand Management Incentive Scheme (DMIS) should also be examined. At present, the DMIS supports the application of an efficient non-network option related to demand management. Since the development of the scheme, most recently in 2017, the focus remained on modifying the drivers of network demand remove a network constraint. The context was largely to address peak demand, where augmentation was considered to meet increased customer energy demand.

In the last years, the integration of DER contains similar issues, although not necessarily aligned with growing peak demand. Hosting capacity for DER can be considered a network limitation, as can voltage rise as a consequence of 'excessive' reverse power flow.

In considering the EFA guideline and assessment techniques, we ask that the AER also consider the application of the DMIS incentives and how they may translate to the challenges of integrating DER.

Question 1 – Information provision – What information is reasonable and necessary in identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services?

The steps noted in section 6 of the AER consultation paper are supported.

Some aspects for consideration in enhancing that approach are:

Identifying the need

- Robust, transparent *forecasting and provision of base data* relied on in reaching their proposal, incorporating as best as possible the industry intelligence, industry and stakeholder data and actual performance that leads to the range of outcomes forecast. To have an appreciation of the need and efficiency of any proposed action by the utilities, customers and stakeholders need to have accepted the input assumptions that drive the forecasting. This is especially important as it is changing customer approaches to energy needs that are one of the fundamental inputs into the needs analysis.
- Any needs statement must include how valid and *informed consumers' preferences* are reflected in the utilities' proposals.
- While networks retain important information on customers and trends in demand, it is essential for confidence that these forecasts are validated against independent and objective data sources.
- There should be a clear line-of-sight between the forecasts of need and the impact of the security, price, reliability and safety of supply. It should be possible for stakeholders to see how a change in 'x' leads to a change in 'y' (e.g. Reliability)

Technology Risk

The risks associated with technology are high, as highlighted by the changes to AS4777 [2], AS4755[3] and the development of network control systems. It is important that the AER assessment is agnostic to technology change and/or the scenario analysis includes assessment against a range of technological futures. Some credit must be applied to utilities that have demonstrated a national approach to technology. DER is marketed nationally, and the fragmentation of connection agreement requirements is a major detractor to efficient application of DER.

Networks need to demonstrate how they approach the risk of technological change within the lifetime of the proposed solution.

Counterfactuals

Utilities need to be encouraged to pursue 'light handed' responses, reflecting the least involvement in new assets and customer constraints. This may not always be possible, but the basic expectations of consumers that utilities continue to avoid adding to the regulated asset base must be recognised.

It is recognised that utilities are often required to err on the side of conservatism in a rapidly changing environment. We seek solutions that tend to focus on monitoring, risk assessment and mitigation and vigilance before moving to solutions that involve traditional poles-and-wires investment.

We also encourage the use of third-party integrated solutions that look beyond just the 'network problem' but work towards facilitating a more holistic energy solution for consumers.

Scenario analysis

The nature of the RIT is supported, including extensive and innovative options analysis in their response.

A risk assessment will need to feature in the assessment techniques. As DER is a changing landscape, networks will need to demonstrate a range of possible outcomes and how the forecasting and responses reflect interpretation of a 'least regrets' approach to investment and operations.

Demonstrations on how valid and informed consumers' preferences are to be reflected in the utilities' proposals.

Balanced quantitative and qualitative cost-benefit analysis is needed. Qualitative benefits, however, need to be clearly explained and justified by robust consumer engagement or other research.

In addition, utilities should be able to clearly show their consideration of DER impacts includes not just the immediate challenges such as voltage management and hosting capacity, but also the wider relationship of DER with their network augmentation proposals, asset replacement options analysis, tariff strategy and network reliability initiatives.

Scenarios should include the option of short-term risk mitigation while waiting for more information (as per AER, p 6-18) before initiating larger, and longer -term investments. NSPs may consider whether a longer-term option could be proposed as a 'contingent project' (with realistic triggers) as part of their revenue proposal to give comfort that the risk of short term option is managed.

We have highlighted the importance of measured and innovative responses to issue such as voltage reduction and tariff reform over the more traditional 'asset based' approach.

Cost-benefit analysis

The CBA for DER is not without its challenges, as we have observed in recent determinations.

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[2] AS4777–2015: Grid connection of energy systems via inverters

[3] AS4755–2007: Framework for demand response capabilities & supporting technologies for electrical products

First, valuing consumer sentiment in the importance of networks supporting a future with more sources of energy from sustainable sources is important, but qualitative. We support strong consumer engagement, integration with government policy and close trend analysis of customer uptake to assist in shoring up analysis and confidence of such benefits.

Second, valuing benefit to customers – both those deeply involved in DER applications and those who are not able to – remains an imprecise science. Some guidance by the AER as to how the impact of DER benefits consumers in terms of qualitative and quantitative impacts would be of great assistance.

Rail-gauge risks, even with data collection

The prescription of data standards and communication protocols will play a role in minimising the interface costs, especially as many data providers span multiple states, customer types and jurisdictions. Despite the attraction of different jurisdictions 'going it alone' in data gathering and technical solutions, this presents a danger of stranded assets or higher costs.

We encourage industry forums such as the DERWG, hosted by SAPN, to work towards a partially standardised approach to data provision and aggregation.

Other issues are:

- The difficulty and risk of prescribing standards and approaches is recognised. There is a real risk, however, that different DNSPs 'going it alone' presents a danger of stranded assets, duplication of effort and higher costs.
- Cross-NSP learning should be encouraged and rewarded. We agree with the AER, that: "it will be important for networks seeking to develop bespoke solutions to make a strong case for any such proposal". (AER, p 6-19)
- We encourage industry forums such as the DERWG, hosted by SAPN, to work towards a partially standardised approach to DER integration. There is also a role for the AER to play a leadership role in providing a framework for research and information gathering.
- Where ICT based solutions are considered, NSPs should seek optimal arrangements, including process changes that do not require bespoke solutions or significant variations from standard commercial ICT products.

Question 2 – Options analysis – What range of options should DNSPs consider for DER related investments? Does the Regulatory Investment Test – Distribution provide the appropriate starting point for this analysis?

The approach to the DER is a reasonable start in this analysis. The 'credible need' will have to incorporate many of the issues noted in Q1 above.

Similarly, matters such as 'capex versus opex' and the impact of policy changes or new tariff structures will need to be considered. It may be useful to focus on opex-based solutions to avoid investment in assets that may have lives that exceed their usefulness in this current changing environment. It would be useful, however, to keep those operating costs out of the 'base year' analysis for opex analysis, to encourage utilities to continually review the capex / opex balance for DER management and ensure the benefit of any change in the approach is passed to consumers.

The fundamental premise of seeking 'non-network solutions' wherever possible is encouraged.

Question 3 – Sampling and modelling – Electricity networks have utilised sampling and modelling techniques to forecast energy demand and consumption for decades. These processes have proven effective for large cohorts of consumers where diversified behaviours can be predicted with sufficient

accuracy. Is it reasonable to assume that sampling and modelling techniques will play a part in developing dynamic models of the electricity networks?

New tools and approaches will be needed in forecasting a utility's investment and expenditure needs. As much of the installations occur on the low-voltage systems (the 'often forgotten-cousin' of the power network), the variability of customer energy demands mean that much better information on the real-time performance of low voltage and high-voltage networks will be needed. Therefore, we are generally supportive of expenditure by networks to better understand network operation, noting that the information required can be provided by a range of sources, including metering data providers, third party system integrators, solar PV system providers and even quality state estimation.

Therefore, while we support expenditure in principle, the NSP must demonstrate that it has investigated options of obtaining data from third parties (an opex rather than capex charge), particularly given the rapid market changes. For instance, with further emphasis on smart meter roll out outside Victoria, the network will have a wealth of information on customers behaviour and customers will have greater incentives to modify their behaviour.

Sampling and modelling will remain a critical part of considering a utility's expenditure requirements, however. As DER is essentially a customer-led phenomenon, the modelling will need to extend to better understanding customer's intentions as to the uptake and application of DER. It will be insufficient to look from the 'network side' to understand the emerging expenditure needs. Variables such as energy price, government policy, customer motivators and manufacturer / supplier incentives will need to feature in meaningful forecasts. Of course, customer drivers are already a major component in planning network capacity augex, reliability requirements or connections activity, it's just that as DER can affect such a wide range of consumers quite quickly, the sampling, modelling trend analysis and forecasting will need to be very timely and versatile.

The sampling and modelling will also require a high degree of transparency, with the input assumptions and ranges being shared with stakeholders, customers and industry. This has two benefit. First, stakeholder support for the expenditure proposed by utilities can be gained by clear involvement and engagement. Second, consumers and industry can adapt DER uptake plans and schedules to extract synergies in the location, timing and nature of DER development to support both customer and network needs.

The publication of 'network opportunity maps' or 'network constraint maps' is an example of these joint opportunities.

There may also be a role for the AER to establish some standards/guidelines for such sampling and modelling. To the extent a NSP undertakes its own research, and consumers fund this research directly or indirectly, and the research flows through to the NSP's revenue forecasts, there must be a minimum standard of transparency and quality. This should not prevent innovative research, but would ensure that consumers can have confidence in the outputs.

Metering

We expect that the requirements of networks to seek new sources of data is inevitable. We can only lament the cumbersome and unremarkable environment that governs the uptake and benefit realisation of advanced customer metering.

The AEMC has committed to monitoring the roll out of advanced meters and the barriers to this, and will commence a review of competitive metering arrangements in Dec 2020. (See AEMC, *Reducing customers' switching times*, Rule Determination, 19 December 2019).

Question 4 – Non-network options – Distributed energy resources are, by definition, located at the end of the electricity network. Typically, networks have less visibility of this part of the network. What approaches or information is reasonable to assess whether DNSPs have considered purchasing the

necessary information from metering or DER data providers rather than building their own assets and systems?

As noted in Q3 above, visibility of the operation and performance of low voltage networks is seen as critical, especially in considering hosting capacity and delivering demand response capability.

It is very important that this visibility is gained in conjunction with other services that provide value to consumers, such as interval metering, demand response and perhaps even peer-to-peer feed-in arrangements.

We have observed in our work with distributors that there is a real concern about the commercial arrangements that may exist regarding the provision of customer data – in particular AMI data – from third party sources. In Australia, that facility is largely unexplored beyond a very small scale, despite the likelihood or of a reasonably competitive market between retailers (as meter providers), third parties (for example Reposit or Solar Analytics) or DER system integrators. We acknowledge some utilities are probing this opportunity, but until someone 'gets it working' it remains largely hypothetical, unfortunately.

Being customer-owned equipment, non-network options may include contracting with the customer to take particular action, such as west-facing panels, load curtailment agreement or providing connection data through a third party. Networks should not be prevented from establishing innovative direct connection agreements with customers, particularly larger DER sites.

Question 5 – Policy and standards – The optimisation of DER can be improved through many different approaches. Factors such as tariff reform, connection standards, technical standards, energy efficiency standards, etc. can greatly impact the way that DER operates on the network and impact on network performance. How should these options be integrated with the development of network DER proposals?

Note the approach outlined in attachment 1 – voltage standards and augmentation - as a possible approach to new standards that are more appropriate for today's energy future. The question is, who would champion such an investigation ?

There is a large gap between what is sensible and reasonably possible, and what is likely to appear in our industry in the reasonable future. Market arrangements, vested interests and the fragmentation of benefits stand between effective solutions and achievable outcomes. We note the work being done in rule changes and reform, despite the fact that DER uptake continues to outpace the needed reforms.

Tariff reform to encourage EV and demand response – not just storage but also water heating, pools, aircon, appliances – is necessary in the efficient and optimal DER response by networks.

Therefore, we look to innovation and a new approach to risk management by utilities as a precursor to traditional investment to meet network limitations emerging from DER uptake.

Another policy issue to be addressed is the falling utilisation of electricity networks. As seen in the well-circulated 'duck curve', peak demand is relatively stable but energy throughput (load factor) is falling. The issue of falling network utilisation must be addressed in any policy response, and standards and investment assessment should be tuned to encourage improved network utilisation wherever possible. Tariff reform encouraging consumption in low-demand periods and attractive load control implementation are options, although it is acknowledged that many possible actions to arrest falling network utilisation are outside the direct control of network operators.

It is also important that these actions are co-ordinated to the maximum possible with retailers.

At the very least, in approving network investment or new revenue for DER integration, networks should be required to show that they have pursued all reasonable avenues to draw benefit from existing assets.

Also significant is the fact that many of the networks, and particularly in South Australia are on average quite old – average 40-50 years in the case of South Australia. As a result, many networks are seeking

investment in replacement capex. It may be worth pursuing whether standards should be set as part of the replacement process in anticipation of expansion of DER. Similar requirements should also apply to new estates. This is another reason for the AER considering the DER options within the broader context of the regulatory proposal.

Question 6 - Cost benefit analysis – Project justifications will require detailed analysis on the costs and benefits of each option. Many of these benefits may be external to the DNSP's cost base and may accrue directly to DER users. What level of analysis is required? 8-23 AER Consultation Paper – Assessing DER integration expenditure

The issue of benefits is discussed at some length earlier in this response.

We note that some investments may not yield positive cost benefit, as they are under the banner of a 'least regrets' response to emerging needs or future requirements. Similarly, investment may be in response to very rare and unlikely 'black swan' events.

It will be necessary for the AER to balance these somewhat speculative investments with the needs of all consumers. Questions like:

- Where does this benefit for all consumers, including non – DER customers, land ?
- Has changing customer behaviour been considered ?
- What will be the impact on specific sectors of the customer base and industry, and how might this be mitigated ?
- What will be the change in network utilisation ?

Question 7 – Customer Benefit – With DER being able to provide services across the electricity supply chain, how should DNSPs identify and value customer benefits? These benefits can include reliability outcomes, increased export potential, greater access to energy markets, access to network support services, etc. Should a common approach to valuing consumer exported electricity be established?

We also look for networks to pursue DER benefits across the whole of their business requirements. It has been recognised that DER can assist in deferring network augmentation to meet Peak demand. Enthusiasm and support for this approach has faded as it is seen that PV has little impact on the more localised network evening peaks, but the adage still holds true for non-residential network segments. DER has the potential to address issues such a low reliability, contingency options and voltage management at times of peak demand. We look to distributors to demonstrated that the costs and benefits of the more innovative and wide-ranging applications of DER are considered.

- Wholesale energy futures ?
- Role of stand-alone or 'skinny feeder' systems
- Local energy trading – role of NER and short-haul DUoS

The AEMC's 2019 Electricity Network Economic Review notes there may be benefits in explicit arrangements for DNSPs in managing export constraints. This is a useful concept, where distributors are offered explicit benefit or consequences for encouraging or constraining DER generation. We see the alignment of distributor's interests in facilitating the efficient application DER with those of consumers as a very powerful initiative. At the moment, there is a strong discontinuity between the two points of benefit, resulting in complex and cumbersome connection arrangements and a tendency to restrict the ability for customers to make full benefit of their DER.

This is amplified by the financial returns to distributors under the current revenue cap framework, where there is little or no incentive for distributors to facilitate DER. This may be an issue to consider in the next round of Framework and Approach discussions for the next round of resets.

We also note the work being undertaken through the DEIP around valuing the costs and benefits of exports, which could lead to a more common approach to valuing energy exports and ultimately more robust cost-benefit analyses.

We would support this initiative of a common methodology while recognising that the actual value may differ in different networks (and parts of a single network) and different times. One concern is to ensure there is equity across consumers. If there are no pricing signals associated with the export limit, then presumably there will be an early mover advantage. The AER suggests that the alternatives for customers who seek to connect once the hosting capacity limit is reached are typically offered a zero-export connection agreement, or an offer to augment the network. We agree with the AER that: "neither the offer of a zero-export connection agreement, nor the augmentation costs represent a long-term sustainable solution to the continuing deployment of consumer DER (p 8-33).

Question 8 – Options value – Noting the technological rate of change and the typical asset life of 65 years of many network assets, it is important to test whether current research could provide a more efficient option in the near future. Should an assessment of emerging alternative approaches be a requirement for DER forecast expenditure? Should there be an 'options value' placed on this?

The CCP is very supportive of the approach taken by Ausgrid in establishing a Technical Review Committee under its Consumer Consultative Panel to provide direct consumer insight and overview of new-technology customer-facing investments. This collaboration assists in identifying the option value of the investment decisions.

We also support the production of a network futures document by utilities that covers not only DER but also the projected needs for assets generally. Such a report would assist in understanding the nature of the investment options and the benefits and projected life of these options.

Question 9 – Shared learning and systems – The development of common platforms, communication standards and shared systems may reduce the overall cost and complexity of facilitating DER. Should DNSPs need to show how they have considered options that leverage shared learning, common standards and common systems to provide efficient solutions, and that they have consulted and implemented learnings from prior works and trials across the NEM

There is an imperative to balance innovation and targeted solutions with the need to use optimised, off the shelf tools as the first option. DER systems, equipment and customer applications transcend jurisdictional boundaries, so a level of standardisation and commonality is critical. We remain supportive of the work by the DERWG instituted by SAPN in this area. We also note the progress of the Open Networks initiative. We acknowledge the role of a network body setting a form of standards, function and oversight, but remain convinced that the individual networks themselves must retain accountability and ultimate control of the role of DER in their jurisdictions.

We support a level of standardisation regarding:

- Standards to inverter control / coordination
- Simple and effective tariffs to encourage optimal DER operation and implementation
- Common connection standards & inverter settings wherever possible
- Approach to the forecasting, assessment and quantification of consumer benefits of DER
- Data interchange standards to facilitate third-party provision of connection performance data
- National advanced metering and communication standards[4]

[4] https://www.aemc.gov.au/our-work/our-forward-looking-work-program/integration-of-DER/grid-of-future

Question 10 – Rail gauge outcomes – as a corollary to the above question, it will be increasingly important for the industry to work together to provide customer outcomes that are consistent across the NEM (or with international standards if applicable). What approaches or information is reasonable to show that any DNSP-specific communication protocols, interfaces, connection standards, etc. will not lead to increased cost and complexity for consumers and industry providers?

This risk is recognised and discussed in our response to Q9. We note the work being done through Open Networks and the ARENA Distributed Energy Integration Programme, supporting information exchange and collaboration on DER issues.

13. Other comments

The emergence of Aggregators and Virtual Power Plants has highlighted the need for a strong working relationship with network operators. VPPs are often operated by retailers or aggregators with a view of responding to wider market signals, such as high pool price, with little awareness of the impact on the local networks of the dispatch of the generation with little diversity. VPPs tend not to have contractual or operating agreements with networks, and the network connection agreement with consumers generally does not consider the risk of undiversified feed-in by multiple VPP sites which are commercially incentivized to operate at maximum export simultaneously.

a) *Tariff development* is a major initiative with the Australian market but is not resonating with consumers as yet. Despite their important role in the new energy environment for equitable cost recovery and customer demand signalling, shifts to dynamic tariffs have a hard road ahead due to consumer wariness and the low penetration of interval meters. Importantly, interval data is needed to assist consumers embrace change when they ask the key question: "if I change tariff, will I be better off ?" Tariff reform will also have a large bearing on the return on investment in behind-the-meter battery storage.

b) *Cost recovery and equity* is another key consideration in the efficient energy transition. Despite the fixed share of the bill increasing in recent years, consumers transitioning to behind-the-meter generation naturally consume less energy from the grid. Under the national electricity legislation, networks can only recover network costs from consumers of energy, not from prosumers feeding energy into the grid. Therefore, the cost recovery is distorted, as utilities are restricted by industry conditions, and advise consumer impacts from being able to equitably share network service costs among all users.

c) *Reform to network use-of-system charges* is needed, especially with peer-to-peer trading highlighted as a major opportunity emerging for consumers. A defining characteristic for behind-the-meter energy resources is that they can be local – that is, located closely to the site of the energy demand. Therefore, the transport arrangements, in the case of networks being the Use of System charge, needs to be redefined to allow networks to charge to move the power short distances, not the 'postage stamp' arrangements that predominate under regulatory cost-recovery requirements today. A key aspect of regulatory reform will be to permit networks to recover Use of System costs for 'short haul', even in the form of an unregulated revenue to 'sell the 'spare capacity' of local networks in times outside peak demand –akin to the 'Uber' or 'Airbnb' of energy, where spare capacity can be monetized.

   This aspect of network charging and optimization of asset utilization will remain a key opportunity *and a regulatory priority.*

d) *Ombudsman schemes* will be very significant in ensuring that third party dispute resolution continues to be available to all energy customers. Any business that can impact on a customer's energy supply needs to be a part of a recognised Ombudsman or third party dispute resolution scheme, including VPPs, aggregators and other DER equipment and / or service providers who are not the retailers or network service providers who are currently scheme members. Increased uncertainty from rapid change will inevitably include less scrupulous operators along with the legitimate. Energy ombudsman schemes are widely used and trusted by consumers and will be important in both providing consumer protection and dispute resolution in DER uncertainty as well as providing a degree of confidence in energy markets to enable customers to engage in DER with more trust than they might otherwise have.

e) *Customers who cannot or choose not to take part in new energy reforms through the investment in new consumer energy* technologies must also be considered. This is a key issue everywhere,

and regulators are very sensitive to keep the traditional energy consumers, who will for some time remain the majority of energy consumers, protected from commercial and technical impacts of more adventurous or perhaps even reckless prosumers. Their position will be important to governments who will need to sanction regulatory changes to enable new approaches to the supply of electricity. One thing about networks is that they do not differentiate significantly between one consumer and the next. The new energy environment will impact *all* consumers, not only those who are in the right situation to embrace new BTM technologies.

f) Finally, it is important to take care not to overcapitalize and overcomplicate networks, market services and customer relationships in response to the continued adoption of DER. Customers have highlighted that trust and sensitivity to cost remain the highest priorities in their approach to the electricity industry; and are keen to seek ways to distance themselves from the industry wherever possible. All these investments – DSO control systems for consumer equipment, market operator registration requirements, new transmission interconnectors and the commercial expectations of new market entrants such as aggregators – present a high risk of 'eating up' much, if not all, of the potential bill savings and precious consumer goodwill.

So many are long term investments too, so if the energy world over time takes the turn to become more 'local' or a collection of many microgrids (as renewable technology can support this approach), many of these large investments could become stranded, but still needed to be paid for by consumers.

Attachment 1 - Voltage standards and augmentation

A predominant driver for network's investment to address DER-related quality of supply and hosting capacity is fundamentally reliant on the application of standards AS 60038 – 2012 and AS6100.3.100. These standards underpin all power quality and low voltage design criteria for distributors in Australia.

For many years, the defining trigger point for low voltage network augmentation has been the drop in supply voltage to below the allowable 216V, generally due to high demand on a cold winter night with a predominance of domestic heating load. Nowadays, utilities are reporting the defining moment to be the exceedance of the high voltage allowed limit of 253 volts when demand is low and embedded generation is high, such as during a mild sunny afternoon.

Essentially, the challenge of acceptable operation of low voltage networks is shifting from the peak demand on low voltage on cool winter nights to high voltage on sunny mild afternoons. This is not universally the case, but it is more and more common.

In our experience, networks base the growing predominance of the exceedance of the high voltage limit as the basis for requiring network augmentation and investment. This is largely the result of the fact that low voltage network design and operation still operates on the expectation that the 'float' or no-load voltage for almost all low-voltage systems is very close to the maximum value of 253 volts.

To their credit, networks generally seek the low-cost option of phase balancing to immediately address local voltage problems, but this often does not help. The next approach is generally augmentation.

In assessing regulatory proposals to date, it is useful to ask: "how many exceedances, or customer complaints, of the low voltage limit are occurring?' Very often, the response is that low voltage exceedances are rare, or certainly less predominant that the high-voltage exceedances created by high penetration of PV. This is mainly due to the fact that energy efficient appliances are predominating in modern households. In recent times, DC (LED) lighting has become commonplace, as has heat -pump space heating, switch-mode power supplies in appliances, DC drive pool pumps and linear-compressor refrigerators. It is reasonable to conclude that the vast majority of households are nowadays much less sensitive to low voltage than exceeding the high voltage limit.

Generally, the lowest-cost response to high voltage is to lower the tapping setting at the local distribution or zone substation transformer. This Is not always possible, but frequently discounted by utilities in preference to augmentation on the basis that lowering the float voltage will 'create low voltage problems.'

In assessing a utility's proposal for augmentation, in particular the factor 'has the DNSP considered a range of practical options?', we encourage the AER and networks alike to aggressively demonstrate that voltage reduction, including managing any consequential customer risks, is preferential to augmentation expenditure.

Ultimately, we should ask "is it time to review voltage standards in light of the new energy environment?"

Glossary

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
Augex	Network Augmentation capital expenditure
CCP	Consumer Challenge Panel
CESS	Capital Efficiency Sharing Scheme
CoGaTI	Coordination of Generation and Transmission Investment (an initiative of the AEMC)
DC	Direct Current (as opposed to AC – alternating current)
DER	Distributed Energy Resources
DM	Demand Management
DR	Demand Response
DNSP	Distribution Network Service Provider
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
EUAA	Energy Users Association of Australia
ICT	Information and Communications Technology
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
Opex	Operating expenditure
PTRM	Post-tax revenue model
RAB	Regulated Asset Base
Repex	Network Asset Replacement capital expenditure
RERT	Reliability and Reserve Trading (Market operator system security action)
RIN	Regulatory Information Notice
TSS	Tariff Structure Statement