Dr Kerry Schott AO
Chair
Energy Security Board
Submission by email to info@esb.org.au

9 June 2021

Dear Dr Schott,

Subject: Energy Security Board (ESB) Post 2025 Market Design Consultation Paper

SA Power Networks welcomes the opportunity to provide feedback in response to the above consultation paper.

South Australia is at the forefront of the transition to distributed energy, and SA Power Networks is committed to playing our part in enabling and accelerating this transition. We have set a public goal to double the amount of rooftop PV we can accommodate on our network by 2025 and we are working with the solar industry and other stakeholders on a range of initiatives to enable this.

Most notably, we are actively progressing our strategy to transition from fixed to flexible export limits for new solar connections in SA by mid-2022, leveraging the capabilities of modern smart inverters and the IEEE2030.5 standard. This was a commitment we made in our 2020-25 regulatory proposal, and we are on track to commence field trials with several leading solar inverter manufacturers in mid-2021, in parallel with similar trials in Victoria led by AusNet Services.

We have also been working with Virtual Power Plant (VPP) operators to explore two key facets of the role of the Distribution Network Service Provider (DNSP) in a future market dominated by high levels of distributed energy resources (DER): the DNSP's role as an enabler of market access for DER and DER aggregators, and the opportunity for DER aggregators to provide network support services to the DNSP. We have recently concluded a successful 18-month field trial with Tesla and their South Australian VPP in which we've demonstrated the ability to use 'dynamic operating envelopes' to signal available network capacity, increasing the VPP's capacity to trade in energy and frequency support (FCAS) markets. We are currently engaged in trials to test the potential procurement of network support services including reactive power support from VPPs.

We have also been actively engaging with the Australian Energy Market Operator (AEMO) and the SA Government over the last three years on the emerging system security challenges in South Australia at times of minimum demand, and the role the DNSP can play in helping AEMO to respond to contingency events that threaten the stability of the system. These concepts were tested for the first time on 14 March this year, when a minimum demand contingency occurred that caused AEMO to direct us to shed around 70MW of generation on the distribution network (mostly rooftop PV) to restore the system to a stable state.

We consider that being on the 'front-line' of the energy transition in South Australia has provided us with unique perspectives on how the industry might best evolve in response to this transition, to deliver the best long-term outcomes for electricity consumers.

SA Power Networks supports the ESB's post-2025 market review process. We have been an active participant in the process since its inception, and we are also engaged with many of the related initiatives currently underway across the sector. It is clear that the future energy system will be significantly different from the one for which the National Electricity Market (NEM) was designed, and our market frameworks will need to adapt accordingly. In a world increasingly dominated by intermittent, zero-marginal-cost renewable energy, the value of energy will reduce, and the value of capacity, flexibility and system services like frequency support will increase.

Equally, the transition from centralised generation to a system increasingly dominated by hundreds of thousands of small-scale distributed energy resources means that the distribution network operator has an increasingly important role to play in the integration of DER with the overall electricity system.

As a member of Energy Networks Australia (ENA), SA Power Networks supports and endorses the industry position put forward by ENA in its response to the above consultation paper. Of most relevance to us as a distribution network is Section 4, *Integration of distributed energy resources and flexible demand*. In Attachment A to this letter, we provide detailed feedback on some specific issues canvased in section 4 of the paper. We also offer some general observations on what we see as the key considerations in future market design, and we ask that these be considered in addition to our detailed submission.

Our key items of feedback are summarised as follows:

1. SA Power Networks supports the ESB's goal to create a future market where DER customers can choose from range of innovative and competitive energy services, switch easily from one provider to another, and are able to maximise the value from their own energy resources and demand-side flexibility.
2. The recent emergence of innovative products and services like wholesale-price-passthrough retail offers (e.g. Amber Electric), electric vehicle (EV) tariffs, virtual power plant schemes and smart hot water systems show that there is considerable scope for innovation in DER integration within the current market framework, or with only minor reforms. While the ESB is concerned primarily with longer-term market reform, it will be important to focus on near-term reforms required to maximise these existing opportunities.
3. Some of the longer-term market reforms contemplated in the consultation paper would likely require considerable cost to customers and create additional complexity. We should be cautious about embarking on these unless we are satisfied that we have exhausted the possibilities within the current framework, especially if the benefits are uncertain. As a general rule:
    a. Market reforms should only be made where they address clearly identified barriers or market failings, and not seek to pre-empt future failings that may or may not occur; and
    b. Where reforms are proposed, any cost/benefit analysis must consider the marginal costs and benefits attributable to the specific reform, i.e. include only those benefits that cannot be realised under the current framework.
4. We need to ensure that the future role of the DNSP is clear. We consider that the role of the DNSP should be to:
    a. Facilitate the connection of DER to the electricity system, including the application of relevant technical standards;
    b. Manage distribution network capacity, including the provision of dynamic export limits or 'dynamic operating envelopes' (DOEs);
    c. Facilitate efficient DER access to new and existing energy markets; and

d. Support AEMO in maintaining system security by activating, when directed by AEMO, 'backstop' measures applicable to load and generation connected to the distribution network. Historically this has included rotational load shedding and emergency under-frequency load shedding. More recently in South Australia it has included contingency generation shedding via several mechanisms, including direct curtailment of rooftop PV.

Although this is broadly consistent with the existing roles and obligations in the National Electricity Rules (NER) and National Electricity Customer Framework (NECF), some refinement may be required as the current rules, in certain instances, define specifically 'what' the DNSP must do (e.g. in relation to under-frequency load shedding) rather than placing an obligation on the DNSP to achieve an outcome. This unnecessarily limits the deployment of innovative alternatives to previous methods, since the rules did not anticipate, at the time of writing, that there could be more efficient solutions available in the future.

5. We must not lose sight of the fact that, under the NECF, there is a triangular relationship between the DNSP, the customer, and the retailer. An example of this is the provision of dynamic export limits, or dynamic operating envelopes (DOEs). Just as with a traditional fixed export limit, a DOE is fundamentally associated with the regulated network service provided by the DNSP to the customer, not part of the energy service provided by the retailer. It is an expression of the network capacity provided to the customer under the customer's agreement with the network business.

   Much of the narrative on this topic in the ESB paper appears to assume a linear relationship model in which the retailer (or future 'trader') is the sole entity that receives the DOE from the network and is responsible for managing the customer's equipment to ensure conformance with the network limits. Such a model would be a reduction in customer choice compared to today, not an enhancement. Customers should have the choice of appointing their retailer or any other agent to manage their DER if they choose to (current VPP schemes would be examples of this), but equally should be able to simply manage this themselves if they prefer (e.g. a customer with a basic solar PV system where the inverter manages the export limit).

6. For any desired outcome we need to consider whether the creation of a new market, or change to an existing market, will be the most efficient means to deliver that outcome. Market-based approaches, especially real-time markets, must be weighed against simpler alternatives such the application of new technical standards or requirements, bilateral contracts or the provision of non-market incentives.

7. We support the fact that the ESB paper recognises the importance of the following work currently underway:

   a. The transition to cost-reflective network tariffs, and the increasing availability of time-of-use retail tariffs. Better tariffs present an immediate opportunity to reward both DER and non-DER customers for shifting discretionary loads to align better with market price and network need, with no change to the current market framework;

   b. The review of the contestable metering market currently being undertaken by the Australian Energy Market Commission's (AEMC);

   c. The AEMC's Access and Pricing rule change;

   d. The work on advancing a national approach to dynamic operating envelopes being undertaken by the Australian Renewable Energy Agency (ARENA) with its Distributed Energy Integration Program (DEIP); and

e. The related work on a national implementation guide for the IEEE2030.5 standard communications protocol (API) being undertaken by the cross-industry *DER API Working Group*.

These activities are key foundations for the effective integration of DER under any foreseeable future market design options and should be supported and accelerated.

8. We support the aims of the proposed Maturity Plan, including the incremental approach to market reform, and the intent to engage customers (through customer advocates) early in the design of reforms that affect them. It is clear, however, that an appropriate governance model will be essential if it is to succeed. The recent Maturity Plan Pilot has illustrated the challenges of seeking to engage a broad range of stakeholders in designing solutions to problems that are deeply technical.

   In our view the most successful recent example of this kind of engagement has been the DER Access and Pricing review. This was an activity that was led initially by customer advocates and maintained a strong customer focus throughout, which has successfully explored a complex area of network regulation with a broad range of stakeholders, most of whom were not experts in the subject matter. It did this by engaging subject-matter experts to develop plausible approaches and present these in a form that non-experts could engage with and influence. On the strength of this and its other ongoing activities in the governance of DER integration efforts, we would propose ARENA's DEIP program as a potential model for governance of a process such as that proposed in the Maturity Plan, with AEMC as the overarching governing body.

9. Finally, our engagement with customers reminds us, time and time again, that their primary desire is for a safe, reliable electricity supply at an affordable price. The ESB must keep customers front-of-mind in the market reform process, and ensure that the future market promotes these outcomes. Any reforms must be informed by appropriate customer engagement to ensure that the future market empowers customers with choices that they want, care about and are able to engage with, and does not simply burden them with increased complexity.

We look forward to continuing to engage with the ESB through the remainder of the post-2025 market review process, and we would welcome the opportunity to meet with the ESB to discuss these matters in more detail. In the meantime, If the ESB has any questions on any aspect of our response, please contact Bryn Williams, Network Strategy Manager at bryn.williams@sapowernetworks.com.au or on 0416 152 553.

Mark Vincent
General Manager Strategy and Transformation

Attachment A – feedback on specific issues

1 Market design principles

When we think of the future market we tend to think of a spot market in which energy and services are bid, traded and settled in real time. However, in a future market where capacity and flexibility can be more valuable than energy, many services may be traded in simpler arrangements such as forward contracts for capacity (like UK Power Network's procurement of demand response for network support), bilateral agreements or other incentives, avoiding the overheads of continuous participation in a real time spot market. This may be particularly true for services provided by DER (see below).

When considering future market design, therefore, it will be important that the ESB maintains an outcome focus and assesses any proposed reform carefully against the National Electricity Objective (NEO). A market is a means, not an end. For any desired outcome we need to consider whether the creation of a new market, or change to an existing market, will be the most efficient and customer-friendly means to deliver that outcome. Market-based approaches, especially real-time markets, must be weighed against simpler alternatives such the application of new technical standards or requirements, bilateral contracts or the provision of non-market incentives.

At a time of rapid, unprecedented change, many aspects of the future grid, future DER technology, and the way future customers will want to produce and consume energy and engage with energy services providers, are difficult to predict. In this context, we do not support 'big bang' reforms that require a significant sunk cost to customers in achieving the reform, but where the long-term benefits rely on assumptions about future customer behaviour or the emergence of new energy services that cannot be known with certainty. In a time of change, optionality, deferral of cost where possible, and the preservation of customer choice and flexibility are all prudent and consistent with the NEO.

SA Power Networks strongly supports a progressive approach to market evolution. Market reforms should only be made where they address clearly identified barriers or shortcomings with current arrangements and where there is a clear line of sight to improved customer outcomes.

Where reforms are proposed, any cost/benefit analysis must consider the marginal costs and benefits attributable to the specific reform, i.e. include only those benefits that cannot be realised under the current framework.

While we understand that the primary aim of this review is to look to the longer-term design of the market, post-2025, we think the paper is right to recognise the importance of some of the short-term 'immediate reforms' identified. Initiatives such as network access and pricing reform, improvements in network visibility, DER standards and the development of 'operating envelopes' are already being actively pursued by distribution network businesses, market bodies and industry groups. These will be necessary foundations under any foreseeable future market design options and should be supported and accelerated. This work, including the pilots and trials currently underway, will also help identify regulatory barriers within the current market, and build understanding of the future costs and benefits of longer-term reforms.

1.1 Maximising opportunities within the current framework

A key goal of the proposed reforms is to encourage greater demand-side participation. We note that customers can and do already participate on the demand side in a number of ways, and new service offerings are already emerging. We are already seeing:

- Innovative new retailers offering wholesale-price exposed tariffs for small customers, including negative feed-in tariffs (e.g. Amber Electric);
- New and more cost-reflective network tariffs such as SA Power Networks 'solar sponge' time-of-use tariff;

- Home batteries aggregated in VPPs trading in wholesale and FCAS markets (Nine separate VPPs now operating in South Australia alone, with a combined capacity of more than 25MW);
- Smart loads such as smart hot water and pool pumps being optimised and aggregated (e.g. Solahart's 'Powerstore', pool-pump aggregator Pooled Energy, etc);
- Dynamic operating envelopes being published by DNSPs; and
- DER contracted for network support services.

This suggests that there is potential to reach a much higher level of demand-side participation before we reach the limits of current market structures. Any future market design process needs to examine carefully where there are real barriers to participation in the current rules or market that need to be addressed. In cases where a low level of participation is simply reflective of the early stages of an evolving market, changing the rules is likely to be counterproductive, especially if it introduces complexity.

1.2 Market services vs technical standards

The ESB has observed that technical capabilities of DER to respond to price signals or activate in response to local response curves, etc., may provide for alternatives to, or reduce the need for, new market services or control mechanisms, e.g. bidding into new Essential System Services (ESS) markets. When considering the merit of mandatory standards vs. market services the ESB needs to consider:

- the outcome that is being sought (e.g. frequency stability), and how it may be delivered at least cost to customers, noting that all customers ultimately share the costs associated with establishing and operating new markets;
- whether there is any material transfer of value from the DER owner to others in the provision of the service that should be compensated for; and
- if a material transfer of value exists, whether a market is the best way to efficiently procure relevant services and allocate such compensation.

For example, a DER technical standard that mandates an emergency response if system frequency goes outside the safe range will have no impact on the DER owner in daily use and may be activated very rarely, if at all. As observed in the ESB's earlier consultation paper, in these cases any potential loss to the owner would be so small that the administrative cost of compensating them (which they would also ultimately contribute to paying) would outweigh the value.

On the other hand, activating a synthetic inertia mode that required a customer battery to reserve a portion of its capacity to provide continuous frequency response would be providing a valuable system service to all customers, at some cost to the DER owner. In this case it would be appropriate for the DER owner to be compensated for providing this service using their own asset.

Where there is a genuine transfer of value, the future market design needs to consider what is the most efficient and appropriate means to reward the DER owner for the value they provide. For example, if there is no realistic prospect of meaningful competition between DER owners (or aggregators) to provide a service, because the nature of the service is such that all parties providing it will face essentially the same cost (i.e. would all bid in at the same price if they were offering the service in a competitive market), then a simple mechanism such as a one-off or annual capacity payment to have the service activated in their DER would be more efficient and appropriate than a real-time market.

An example of a service that has value to all customers, but has almost no marginal cost to provide and little prospect of price competition between providers, is the provision of basic (not real-time) interval voltage data from smart meters to networks. In this case a simple addition to the relevant technical standard (the minimum standard data set) would have been a much more effective approach to achieving the network benefits intended from the smart meter rollout than the creation of a new service and a new market for that service, which has so far not succeeded. It would have put DNSPs in a much better position in terms of visibility of their Low Voltage (LV) networks than they are today. We consider this a relevant case study for the ESB in considering the post-2025 market design.

2 Roles and responsibilities

2.1 The role of the DNSP

Consistent with the existing roles and obligations in the NER and NECF, the DNSP in the post-2025 market will remain responsible for:

1. Connecting customer DER to the electricity system;
2. Providing sufficient network capacity to meet customer demand[1];
3. Maximising customer access to available capacity;
4. Rewarding efficient use of the network;
5. Maintaining safety, quality and reliability of supply at the distribution network; and
6. Supporting AEMO in managing system security issues.

We elaborate on these responsibilities below.

1. Connecting customer DER to the electricity system

The DNSP is responsible for facilitating the connection of DER to the network, including the application of relevant technical standards relating to network and energy system compatibility.

2. Providing sufficient network capacity to meet customer demand

The DNSP has a primary obligation under the NER to forecast the demand for network capacity and propose, in its 5-year regulatory determination, a prudent and efficient program of network expenditure to meet this demand.

This can be a combination of capital investment in upgrading network physical assets, investments in control systems that enable greater capacity from existing assets, or procurement of non-network solutions from DER owners or aggregators to reduce local peaks in demand.

Under the NER today, this obligation only applies to the provision of downstream capacity; the provision of upstream (export) capacity is on a 'best efforts' basis. The AEMC Access and Pricing rule change[2] is seeking to address this and establish an equivalent obligation on DNSPs to provide upstream capacity, with associated service levels and performance standards for DER export. This is a critical foundational reform to support a high-DER market, as without it the future opportunity for DER to participate in upstream markets is likely to be severely limited by limitations in network upstream capacity.

3. Maximising customer access to available capacity

DNSPs historically manage customers' use of network capacity through static capacity limits written into the customer's network connection agreement, which reflect the physical limits of the connection. In South Australia a residential customer with a standard single-phase connection will have an import limit of ~14.5kW (63A) and an export limit of up to 5kW. The import limit is backed by

[1] Where 'capacity' refers to both consumption (downstream) and export (upstream) capacity

[2] AEMC draft determination, Access, pricing and incentive arrangements for distributed energy resources, accessed at https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

a physical fuse at the connection point, and the export limit is a hard limit configured into the customer's solar or battery system at the time of installation.

As upstream network capacity is becoming exhausted at certain times in some regions with high rooftop solar penetration, SA Power Networks is moving to introduce flexible export limits for new solar customers in place of static ones. With this approach, a customer's solar inverter can download a variable export limit from SA Power Networks via the internet (using the IEEE2030.5 standard) that reflects the available upstream capacity in the local area at a given time, rather than having a permanent limit set for the worst-case. This means that the system can continue to export at high power most of the time (increased from 5kW to 10kW per phase in SA Power Networks' scheme) even in congested areas, with the limit only being reduced at times when the network is heavily congested. This kind of flexible connection agreement – an example of a network 'dynamic operating envelope' in action – is being trialled with solar customers in South Australia and Victoria from mid-2021[3], following a successful 18-month trial of the approach with Tesla's South Australian VPP[4].

As customers have access to more smart devices, there will be increasing scope for DNSPs to offer customers more flexible connection arrangements for both upstream and downstream capacity. The DNSP's role will continue to evolve from simply ensuring customers have enough network capacity to supply their own appliances, to also ensuring that the network provides DER customers with the capacity they require to use their DER to participate in markets. Dynamic operating envelopes will enable DNSPs to offer customers a choice of connection services: some DER customers may want access to higher levels of network capacity to maximise their market opportunities, while others may prefer to reduce their network costs by operating their flexible loads and generators outside of peak times, taking advantage of spare capacity.

4. Rewarding efficient use of the network

A key part of the role of the DNSP is to promote efficient use of the shared network for the benefit of all customers. To this end, DNSPs are required by regulation to pursue network tariffs that are cost-reflective. Cost-reflective tariffs incentivise customer behaviours that are, on average, beneficial for the network in the long term, such as shifting loads out of peak times. This reduces the long-term need for network investment, keeping network costs down for all.

Cost-reflective network tariffs, such as SA Power Networks' 'solar sponge' time-of-use tariff, create immediate opportunities for customers to be rewarded when they use their flexible loads and DER in ways that support the network. They create a value stream that is accessible to all; non-DER customers can save money with behavioural changes or the use of simple tools like timers to run their appliances outside peak times, while DER customers or their aggregators can achieve further savings using batteries and other smart DER. Increasing exposure to cost-reflective network tariffs is a key opportunity that should be pursued in the short term, which includes supporting efforts to accelerate the roll out of the smart meters required to enable them, something the AEMC is actively examining in its review of the contestable metering market. If the AEMC Access and Pricing rule change is successful, DNSPs will be able to offer tariffs that include credits or rewards as well as costs, allowing for stronger incentives for efficient use of the network.

While tariffs provide long-run price signals, DNSPs use non-tariff means to target short-run and/or locational constraints. Traditionally this has been limited to demand-response programs that target peak demand reduction, but in the post-2025 market – assuming the AEMC Access and Pricing reforms

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[3] SA Power Networks 'Flexible Exports for Solar PV' trial, details available on ARENA's web site: https://arena.gov.au/projects/sa-power-networks-flexible-exports-for-solar-pv-trial/

[4] SA Power Networks, *Advanced VPP Grid Integration Knowledge Sharing Report*, May 2021, accessed at: https://arena.gov.au/projects/advanced-vpp-grid-integration/

are successful – this will extend to targeting constraints in upstream capacity as well. Examples could include:

- DNSPs directly engaging customers who want to opt in to network support schemes, as in the existing air-conditioner and pool pump demand-response programs run by Energy Queensland;
- DNSPs contracting with VPPs or other DER aggregators in bilateral contracts to provide network support services, with the aggregator sharing the value with end customers according to the terms of its particular customer service offering; or
- DNSPs procuring network support services through a new market platform on which DER owners and aggregators can register and compete to provide services.

The future market design should support all of these approaches. In any of these cases, the service in question could be procured on a 'dispatch' basis, with payments made each time the service is invoked, on a standing capacity basis, or a combination of both. Standing capacity-based arrangements may be preferred in many instances since they would avoid the complexity, baselining and transactional costs of dispatch-based arrangements. An example of standing arrangements could be DNSPs offering a fixed annual per-device or per-capacity payment for customers or DER aggregators to program a particular Volt/VAr response curve into their DER.

5. Maintaining safety, quality and reliability of supply at the distribution network

The DNSP is responsible for maintaining safety, quality and reliability of supply at the distribution network for all customers, which includes managing the technical impact of high levels of DER on the network.

6. Supporting AEMO in managing system security issues

System security is not the responsibility of the DNSP, it is the responsibility of AEMO.

However, it has long been recognised that some interventions that can support the system during contingent events can be most effectively undertaken within the distribution network. Traditional examples relate to excess-demand contingencies and include the rotational load shedding and emergency under-frequency load shedding (UFLS) schemes that DNSPs operate on behalf of AEMO.

In the post-2025 high-DER electricity system, DNSPs will need to provide new services to help AEMO manage new kinds of contingency events associated with periods of low demand and low levels of synchronous generation, such as are now arising in South Australia. These will include:

- Enhanced UFLS schemes that do not inadvertently shed generation in areas of reverse power flow in the distribution network, by discriminating more finely between load and generation;
- Potentially new automated 'over frequency generation shedding' schemes;
- Contingency generation shedding schemes, including the emergency curtailment of exports from small-scale rooftop PV. We consider that this is best achieved through an emergency export limiting command delivered via the same API used for communicating dynamic operating envelopes, and not through a separate channel or the physical disconnection of the solar inverter. The API approach has the benefit that it does not require a separate communications channel or a physical isolation switch in the switchboard, and it allows for more sophisticated response behind the meter (potentially via an aggregator) such as activating a battery or load to bring site exports to zero rather than simply curtailing all solar output, which will reduce any negative impact on the customer;
- Use of DNSP capabilities such as network voltage management to help respond to severe supply/demand imbalances; and
- Provision of load to support system restart in the event of a wide-spread system black event.

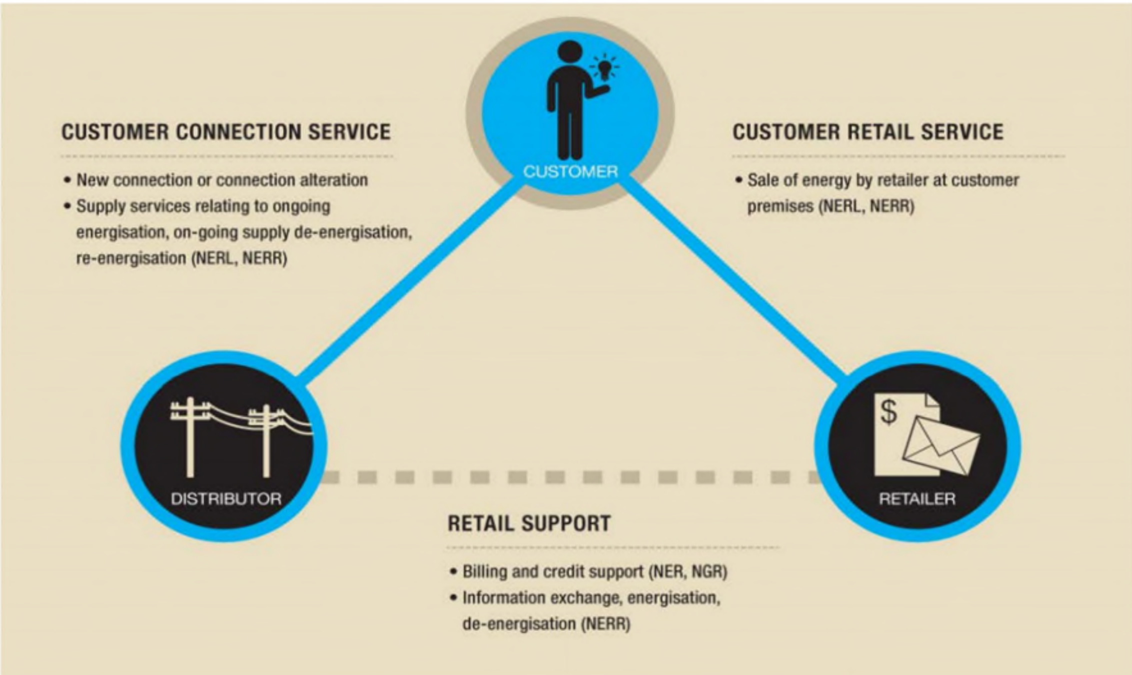
It is important that any contingency curtailment of DER requested by AEMO is enacted through the DNSP and not some other pathway. As well as being consistent with the DNSP's responsibilities under the rules, this is important because the DNSP understands the dynamic state of the network and has available to it several methods to curtail generation within its network, including run-back of SCADA-connected generators, emergency shifting of network voltage, and curtailment of API-connected DER, and can activate these in merit order to achieve the required level of generation reduction with the least risk and least impact to customers. This occurred in South Australia during the minimum demand contingency on 14 March 2021, when SA Power Networks activated several methods of curtailment in order to achieve the level of generation reduction requested by AEMO[5].

We note that the current application of these frameworks within the rules are, to some extent, reflective of traditional approaches to managing, for example, under-frequency load shedding. Some refinement of rules in this area may be required to allow distribution businesses to deploy more innovative solutions that may not have previously been available, and may prove more cost-effective.

2.2 The DNSP's relationship with the customer under the NECF

Under the NECF, there is a triangular relationship between the DNSP, the customer, and the retailer, as shown in the figure below[6].

Figure 2.3 NECF arrangements – retailer, distribution and consumer relationship



An example of this is the provision of dynamic export limits, or dynamic operating envelopes. Just as with a traditional fixed export limit, a DOE is fundamentally associated with the regulated network service provided by the DNSP to the customer, not part of the energy service provided by the retailer.

[5] See: https://aemo.com.au/en/newsroom/media-release/solar-pv-curtailment-initiative-by-sa-government-supports-the-nem

[6] AEMC, *Power of Choice giving consumers options in the way they use energy. Final Report*, 2012, p.47

It is an expression of the network capacity provided to the customer under the customer's agreement with the network.

Much of the narrative on this topic in the ESB paper appears to assume a linear relationship model in which the retailer (or future 'trader') is the sole entity that receives the DOE from the network and is responsible for managing the customer's equipment to ensure conformance with the network limits. Such a rigid model would be a reduction in customer choice compared to today, not an enhancement. Customers should have the choice of appointing their retailer or any other agent to manage their DER if they choose to (current VPP schemes would be examples of this), but equally should be able to simply manage this themselves if they prefer (e.g. a customer with a basic solar PV system where the inverter manages the export limit).

2.3 Dynamic operating envelopes

As noted above, the primary role of the distribution network in the future market is as an enabler, and a primary function is the provision and management of sufficient network capacity, including export capacity, for DER to access markets and trade energy and services.

We consider that dynamic operating envelopes are a fundamental enabler of the efficient management of network capacity in a future high-DER market, and the ESB should support the efforts underway within industry and under the ARENA DEIP program to develop a nationally consistent approach to DOEs, and a national implementation guide for the associated technical standard, IEEE2030.5.

To summarise our perspective on the role of DOEs in the future market:

- Dynamic operating envelopes are an expression of the physical capacity of the network available to the customer. As such:
  - they are fundamentally part of the network's connection agreement with the customer under the NECF; and
  - they must be made available to all customers, including those solar customers who are otherwise passive and not engaged in markets and do not want a third party controlling their resources – who are likely to remain the majority for many years. In practice, this is achieved for these customers simply by customers' smart inverters accessing dynamic limits from the DNSP using the IEEE2030.5 communications protocol.
- This does not preclude more sophisticated customers agreeing to their trader or VPP aggregator acting as their agent and receiving and managing DOEs on their behalf. In practice this simply means that for these customers it is the trader's system, not the customer's equipment, that communicates with the DNSP to access the limits, with the trader's system then configuring the customer's equipment accordingly. This in turn allows for more complex arrangements, such as the DNSP providing DOEs representing the aggregate capacity for multiple customers directly to their trader (we have tested this in our trial with Tesla's VPP), or even the trading of network capacity between parties. But any future framework to enable these things must do so from the foundation that network capacity fundamentally belongs to the customer, as it is the customer, not the trader, who has the connection agreement with the network.
- While DNSPs will use DOEs to express available capacity, they will also engage DER owners or their traders to procure network support services to increase capacity or alleviate local constraints where appropriate, e.g. by providing voltage support, or simply turning down their own use of the network. This will have the effect of increasing the DOEs made available to all customers in the area, but is a separate activity to the provision of DOEs.

- In considering the Access and Pricing rule change, stakeholders have raised the reasonable concern that DNSPs could, in their regulatory determination, have an approved regulatory allowance for upgrading network capacity to the level customers want, but then choose to avoid the cost of these upgrades (or the relevant non-network solutions) during the regulatory period by simply using DOEs to manage customers' use within existing capacity. The Access and Pricing rule change addresses this issue and aims to put in place appropriate incentives and penalties on networks, as well as reporting and transparency requirements, to ensure that this cannot occur. The question of how networks should demonstrate the fair and transparent allocation of network capacity more broadly is also being examined by the ARENA DEIP Dynamic Operating Envelope Working Group, which is working to produce national guidelines for DNSPs in this regard.
- During rare system contingency events, if DNSPs are directed by AEMO to activate emergency load or generation shedding then they should be able to do this using the same API used to provide DOEs, as this will facilitate the best customer outcome and avoid the cost of duplicate communication pathways and inelegant backstop measures such as hard-wired isolation switches. Current and ongoing work on standards in this area should prioritise this use-case.

2.4 Other considerations

Regarding future roles, the ESB paper poses the question "Under what situations could the distribution network operator perform the role of the retailer / aggregator?". We **do not** consider that the DNSP should play a role as a retailer or aggregator bidding DER services into energy markets. The DNSP's primary role should be (a) to ensure that the operation of DER (individually or in aggregate) does not breach technical limits of the distribution network or energy system, (b) to support the use of DER by DER owners and their aggregators to create value and participate in markets, and (c) to identify and publish opportunities for DER to provide network support services, and to engage DER, either directly or via aggregators, to provide these services where it is efficient to do so.

Finally, as a general principle, the post-2025 market design should actively encourage and enable DNSPs to pursue opportunities to use assets deployed to support the network service to deliver benefits to the broader market where possible. An example of this would be the recent trials in which Victorian networks were able to provide emergency load balancing services under the Reliability and Emergency Reserve Trader (RERT) scheme using voltage management capabilities in the distribution network[7]. Any opportunity to use technology to deliver additional benefits from the shared network assets that all customers pay for should be supported, as this is consistent with the NEO.

3 Our feedback on the proposed 'immediate reforms'

3.1 Risk based approach for assessing customer protections

We support the proposed risk assessment framework. We agree that the benefits assessment in the proposed Risk Assessment Tool, including the questions included below, would be a valuable test to apply to any proposed regulatory change that is intended to impact on consumer service offers, including those proposed in the options paper.

[7] See United Energy's "Distribution Demand Response" trial, details available at: https://arena.gov.au/projects/united-energy-distribution-demand-response/

- What does the new service/innovation allow the consumer to do that they couldn't do before?
- How are these impacts likely to change as the future energy system changes? Will these benefits only be realised in the future?
- What evidence is there that consumers want this? And whether it solves any problems they are currently facing?

We support building this kind of risk assessment into any future process for ongoing reform such as the one proposed in the Maturity Plan, and we support the idea of an ongoing periodic review of whether consumer protections are adequate in light of changing service offerings in the NEM.

3.2 Minimum demand

AEMO is the system operator and is responsible for ensuring that the system is operating in a secure state at all times, meaning that it can withstand any credible fault without a system-wide blackout. This includes managing the specific system security risks that are now emerging at times of minimum demand.

This is a complex technical issue involving a number of related risks associated with very low levels of system strength and inertia, the loss of efficacy of traditional backstop measures such as under-frequency load shedding, and the emerging potential for an un-recoverable loss of generation due to widespread tripping of solar inverters in response to disturbances that would have previously been recoverable.

AEMO has conducted an initial study into these emerging risks in the context of the South Australian electricity system, and has published its findings in a report prepared for the SA Government in May 2020 entitled *Minimum operational demand thresholds in South Australia*[8]. This report examines a broad range of potential mitigations, including incentivising customers to shift discretionary loads to the daytime. It concludes that while load shifting is valuable, it is not sufficient to mitigate the risks, given the rate of uptake of new solar generation compared to the amount of load that could plausibly be brought on in the middle of the day. AEMO's analysis indicates that there is a need for emergency backstop measures that can curtail solar output at source, as exist for larger generators in the NEM.

We note that the ESB paper is concerned primarily with minimising the potential negative impact on consumers of such backstop measures, and with exploring new opportunities to incentivise customers to bring on load during minimum demand times. These are important considerations.

We support the development of new market 'turn up' services such as a 'reverse RERT', noting that the wholesale market already rewards load turn-up at minimum demand times through low or negative prices, to which aggregators like VPPs are already responding in South Australia. In time, as retail tariffs evolve, we would hope that more customers will have direct access to lower retail prices at minimum demand times reflective of both the low wholesale price and lower network tariff at these times. Rewarding customers through better retail tariffs will encourage shifting of discretionary loads, reducing the need for services like RERT and for emergency technical backstops.

Customer DER also has an extremely important future role to play in maintaining system security at times of low demand. VPP aggregators are already using customer batteries to provide FCAS services, and they are now working to implement more advanced capabilities like synthetic inertia, leveraging the millisecond response potential of batteries.

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[8] AEMO, *Minimum operational demand thresholds in South Australia*, May 2020, accessed at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review

While these capabilities address some of the risks identified by AEMO, and will help to reduce the circumstances in which off-market interventions are required in the future, they do not remove the need for technical backstop measures. Technical backstops remain critical in addition to market measures when there is excess distributed generation in the market, just as load shedding today provides a technical backstop should the market have a deficit of centralised generation.

AEMO's analysis indicates that, while strengthening the set of market services to target minimum demand will be important, there is a technical limit to the amount of un-controlled generation that can be integrated with the electricity system. We are reaching that limit in South Australia, and will reach it in other jurisdictions in time. We need to move urgently to national standards for small-scale DER that incorporate the facility for emergency curtailment when required. Just as with load shedding, these backstops are only required in rare circumstances when the market can no longer keep the system within secure operating limits, but they are extremely important in protecting the overall integrity of the essential electricity system at these times.

As described in section 2 above:

- it is important that any contingency curtailment of DER requested by AEMO is enacted through the DNSP and not some other pathway; and
- DNSPs should activate emergency load or generation for DER using the same API used to provide DOEs.

Alternative pathways recently put in place in South Australia involving physical disconnection of the inverter via a second meter or other means should be recognised as interim measures that the SA Government deemed necessary to address an immediate risk, and not a template for a national approach. The SA Government's 'smarter homes' reforms[9] recognise that remote export reduction via an API is the long-term solution, and are mandating this capability in new solar inverters in SA.

3.3 Tariff and pricing reform

We support the recognition in the ESB paper of the importance of ongoing tariff reform. Giving customers access to tariffs that more closely reflect wholesale market and network costs will go a long way in enabling customers to realise value from their own DER or demand side flexibility, whatever their level of sophistication. We support the need to accelerate the availability across the NEM of time-of-use and other tariffs that reward customers for efficient use of the system, including the AEMC's current examination of ways to address the slow rollout of smart meters.

In response to two specific issues raised on page 61 of the paper:

- We agree with the ESB's finding that the concept of retailer portfolio-level network charges raises issues that are 'non trivial'. Applying a single aggregated network charge to the retailer instead of a per-customer tariff would appear to be inconsistent with the NECF and would conflict with the pricing principles in the rules that require network tariffs to be cost-reflective, given that an aggregated portfolio-level load profile reveals nothing about the actual drivers of network cost in the system (by way of example, the aggregated load profile for a retailer who has only residential solar customers may be zero for much of the year, even though the energy that these customers are exchanging through the distribution network may be driving the need for local network augmentation).
- We agree with the ESB's finding that future more sophisticated network charging arrangements like dynamic locational network pricing or real time capacity auctions would be

[9] Government of South Australia, 'Regulatory Changes for Smarter Homes' reforms, details available at: https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes

"complex and likely highest cost to implement, which would need to be considered against the potential benefits case for all DER and non-DER customers in the long term".

4 Our feedback on the proposed 'initial reforms'

4.1 Trader services

We don't have a strong view on this as this is more a matter for retailers and aggregators, but we would support reforms that:

- are targeted at addressing identified issues with current arrangements;
- where these issues have a material impact on cost for current market participants or create material barriers to entry for prospective ones;
- where there is confidence that any benefits created will flow down to customers; and
- where it can be demonstrated that the flow-on benefits to customers will be greater than the cost associated with implementing the reforms.

4.2 Flexible trading arrangements

We support the desire to ensure that customers have access to a rich, competitive and innovative market for energy services, but we are concerned that the proposed multiple trader models would introduce considerable complexity for both customers and the market with uncertain benefits. We note:

- Many customers already find it difficult to engage with the level of choice they have in today's market, preferring to remain with their incumbent retailer even when better offers are available. Multiple trading relationships should only be considered if there is a clear desire from customers for these kinds of arrangements, and evidence that customers are able to engage in and benefit from these kinds of choices. We would suggest that customer trials would be required to explore these matters before proceeding with any changes to the market;
- There appears to be significant complexity, and the risk of duplication and inefficiency, with either of the models proposed;
- To get the most out of their resources, customers will need to co-optimise their flexible loads, solar and other DER. Splitting the control of individual devices out to different parties who don't know what the others are doing takes away the ability to co-optimise and will likely lead to sub-optimal outcomes. In practice this may mean that, in a future multiple trader market, traders who specialise in managing individual resources cannot compete with those who manage the customer's entire site, who can gain greater benefits from co-optimisation and value stacking; and
- Multiple trader models also raise issues with the customer's ability to comply with the technical limits of their network connection, notably DOEs provided by the DNSP.

Regarding model 1:

- From a DNSP perspective this has the benefit of being easy to accommodate with minimal change to systems. However, this option raises concerns such as:
    - Electrical safety risks (e.g. ensuring safe isolation where there are two supplies to the premises);
    - meter board space and switchboard costs;

- risks of customers 'gaming the system' by switching loads from one provider to the other. The paper describes this as a positive opportunity for customers to arbitrage against different trader offers, but it is hard to imagine traders supporting this behaviour if it undermines the financial assumptions on which their customer offers are based;
    - The potential need for rewiring every time the customer wants to change their combination of providers, leading to customer cost and the risk of lock-in;
    - The requirement to split the network tariff across multiple NMIs, which is likely to weaken the ability to send cost-reflective network price signals when customer load is disaggregated into multiple sub-loads; and
    - costs and complexity to the customer generally from the electrical requirements – what if there are three or four meters, not just two?
- We note that some arrangements like model 1 exist in the market today, but not for the purpose of providing two separate trading relationships with the customer. We see this where customers have DER assets at their premises that are owned by their retailer, with the multiple metering arrangement provided to allow the customer to end its relationship with the solar & battery owner and take on another (single) retail relationship, without the original owner losing access to their assets.

Regarding model 2:

- Something like model 2 appears more elegant and flexible for the customer and more likely to be workable for multiple services into the same home, particularly if the sub-metering can be done by meters embedded in devices. But this model also raises many of the same issues as model 1.
- The ESB paper says that an advantage of model 2 is that a customer would only be exposed to a single DNSP tariff applied at meter #1. We understand that the intention is that retailer #1 would recover the network tariff based on the total net load profile at the connection point, but levy its energy costs based on the load profile net of any sub-metered loads, which are being supplied by other traders. If this is the intention, this would appear to negate the ability for customers or their traders (other than retailer #1 who, under this model, is likely to be only serving the customer's non-flexible load) to respond to cost-reflective network pricing. In this model a trader who is supplying energy for the customer's electric vehicle charger or air-conditioner has no incentive to respond to network tariffs, as they would be giving retailer #1 – presumably a competitor – a 'free kick' by reducing retailer #1's apparent costs to the customer, while gaining no benefit themselves.

Future reforms should not *require* customers to engage aggregators to manage their DER, nor assume that they will. While some customers will embrace VPPs and other aggregation schemes, many may prefer to respond to time-of-use tariffs and/or optimise their solar self-consumption using their own smart appliances, or engage an independent third party to optimise their resources for them against their preferred retail tariff. DER customers who are not enrolled in aggregation schemes will still benefit from network operating envelopes, e.g. through smart solar inverters. The future framework needs to maximise customer choice and benefit and empower all customers, whatever their level of sophistication and engagement.

4.3 Scheduled lite

We understand that the ESB is concerned that as the system shifts towards more intermittent renewable generation, DER and demand flexibility, it becomes more difficult for AEMO to accurately forecast demand. This makes the spot market less efficient and drives cost, as increasing forecasting error leads to more use of FCAS, RERT and other interventions to manage the delta. It is proposed that the way to address this is to try to encourage flexible loads to be scheduled, reducing one source of unpredictability.

As a DNSP we fully support the intent, but we do not have a strong view on the specific mechanisms proposed as this is more a matter for market participants. Our observation from the ESB workshops was that participants understood and supported the need for more visibility of the behaviour of controlled but unscheduled DER, but generally felt that the proposed incentives (reduced FCAS causer-pays costs, etc.) may not be sufficient to encourage aggregators to opt-in to either of the proposed models. The 'visibility' model, as the less onerous for participants, was seen as preferable to the 'dispatchability' model.

We would note that DNSPs also require forecasts of load flows in the distribution network and will need to collaborate more actively with AEMO on forecasting in the future market. Any forecasts self-provided by DER aggregators under a future scheduled lite regime should be made available to networks also. Conversely, networks contracting DER for local network support services, or undertaking other planned actions that may impact on the amount of energy settled in the market should share forecasts with AEMO.

4.4 Technical standards – interoperability and communications

We agree that a key enabler for ensuring that DER can be activated and participate in markets, and customers can easily switch between different DER service providers, is common technical standards for DER communication, interoperability and cyber security. We support the high-level principles proposed in relation to technical standards.

SA Power Networks is actively engaged in several processes currently underway in this area including:

- The ESB's review of DER standards governance arrangements, and associated rule changes;
- The ARENA DEIP Interoperability Steering Committee (formerly the Standards, Data and Interoperability Working Group) and its various task forces;
- The industry DER API Working Group that is progressing a national standard implementation guide for IEEE2030.5 for DER / network integration, modelled after the work being undertaken in California. SA Power Networks was a founder member of this working group and has been a strong advocate of this approach and the IEEE2030.5 standard for this purpose; and
- SA Power Networks' own award-winning *Advanced VPP Grid Integration* trial and recently-announced *Flexible Exports for Solar PV* trial, which are demonstrating the practical application of these technical standards to integrate smart DER with the network and manage network hosting capacity, and exploring the customer benefits.

We are highly supportive of measures to put in place national standards that ensure that:

- All new DER is communications-enabled and can be configured at the time of installation to connect to the local network utility server for registration and the receipt of dynamic operating envelopes;
- Significant flexible loads such as air conditioners, pool pumps, electric vehicle chargers and hot water services are able to be activated for control in standard ways at low cost to consumers;
- Devices are interoperable and can be readily linked to Home Energy Management systems for local optimisation in response to price signals, or to aggregation schemes or VPPs, and customers can readily transfer their devices from one aggregator or control scheme to another. An example of this would be the US standard 1541 which states that devices must

provide a local interface based on one of three open standards (IEEE2030.5, Sunspec or DNP3); and

- Tariffs and other price signals can be published from retailers to customers' DER in a standard way.

5 The Maturity Plan

We support the aims of the proposed Maturity Plan, including the incremental approach to market reform, and the intent to engage customers (through customer advocates) early in the design of reforms that affect them. It is clear, however, that an appropriate governance model will be essential if it is to succeed.

The recent Maturity Plan Pilot on the topic of 'minimum demand' has illustrated the challenges of seeking to engage a broad range of stakeholders in designing solutions to problems that are deeply technical. In the first two workshops the group has only been able to scratch the surface of an issue that has been explored deeply and at length by AEMO's technical experts in the context of the very real risks to system security that have emerged in South Australia at times of minimum demand.

In our view the most successful recent example of this kind of engagement has been the DER Access and Pricing review. This was an activity that was led initially by customer advocates and maintained a strong customer focus throughout, which has successfully explored a complex area of network regulation with a broad range of stakeholders, most of whom were not experts in the subject matter. It did this by engaging subject-matter experts to develop plausible approaches and present these in a form that non-experts could engage with and influence. On the strength of this and its other ongoing activities in the governance of DER integration efforts, we would propose ARENA's DEIP program as a potential governance model for a process such as that proposed in the Maturity Plan, with AEMC as the overarching governing body.