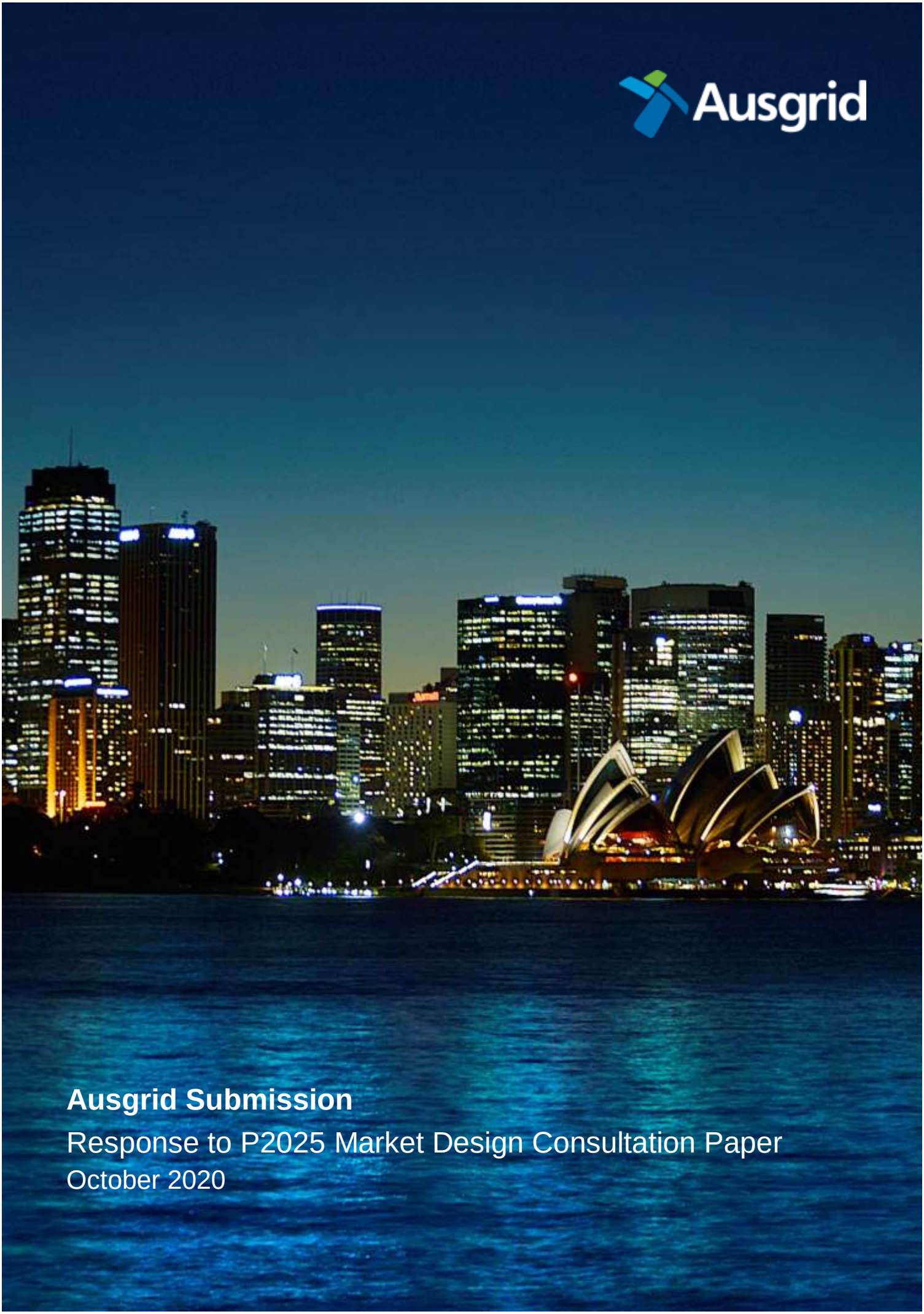

Ausgrid Submission

Response to P2025 Market Design Consultation Paper

October 2020

19 October 2020

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Dr Kerry Schott AO
Independent Chair
Energy Security Board

Submitted by email: info@esb.org.au

Dear Dr Schott,

Ausgrid is pleased to provide a response to the Energy Security Board (ESB) Post 2025 Market Design Consultation Paper (the Consultation Paper) on options for the 7 Market Design Initiatives (MDIs), published in September.

Ausgrid owns and operates a shared distribution grid that stretches from southern Sydney to the Upper Hunter Valley, including the Sydney CBD. Our network supports over 20 percent of the national gross domestic product and over 4 million people who live or work within our network area. We see our grid as a shared, open platform, upon which a new ecosystem of products and services will evolve.

We support the efficient evolution of the energy system in a way that reduces costs across the supply chain, while at the same time providing customers more choice and control. As Australia's electricity becomes increasingly sourced from variable renewable generation it is paramount that we unlock flexibility on the demand side to better match the supply of energy and reduce overall system costs. In order to realise this transition, now more than ever a collaborative and customer centric approach is required to co-design a sustainable, affordable and reliable energy system. We appreciate the significant effort that the ESB and market bodies have put in to provide transparency and clarity on your current views on the 7 MDIs.

We broadly agree with the ESB's views of the role of networks as stated in Section 9 of the Consultation Paper, noting that our role will continue to change over the coming decade. As a Distribution System Operator (DSO) we will increasingly use a combination of market-based approaches and smart assets (such as community batteries and dynamic voltage control) to address network constraints, provide Distributed Energy Resources (DER) with access to markets and dynamically allocate capacity in the network.

We are starting to trial these new capabilities now, supported by a focus on cost reflective network pricing reform. Through our new Network Innovation Advisory Committee (NIAC), we are collaborating with customers on the innovative projects that will enable the transformation of our network. It is important that we are allowed and encouraged to evolve to ensure efficient use of shared network assets across Australia in the future. Appropriate investment signals must be maintained to support networks developing these capabilities if we are to deliver better customer outcomes in the long term.

Please find attached responses to a selection of the consultation questions posed in the Consultation Paper. If you have any queries in respect to this submission, please contact Alida Jansen van Vuuren on 0411 436 108 or alida.jansenvanvuuren@ausgrid.com.au.

Regards,

Rob Amphlett Lewis
Chief Customer Officer

Response to consultation questions

Section 4 - Resource Adequacy Mechanisms - Market Design Initiative A

No comment.

Section 5 - Ageing Thermal Generation Strategy - Market Design Initiative B

No comment.

Section 6 - Essential System Services - Market Design Initiative C

1. What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a Post-2025 NEM? What are the benefits of this approach? What are the costs and risks?

No comment.

2. What are your views about developing Fast Frequency Response with FCAS and developing a demand curve for Frequency Response? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements. What additional mechanisms might be needed to foster investment for a Post-2025 NEM. What are the benefits of this approach? What are the costs and risks?

Fast frequency response is a key system service for the evolving NEM, and the establishment of this new market will likely incentivise investment and support a more reliable and secure power system. This includes unlocking additional value from new solutions such as batteries and virtual power plants that Ausgrid is already trialling for network support.

3. What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?

As identified by FTI these services have limited scope for competition and, in the case of system strength, are not easily defined or measured. Therefore, in the short to medium term NSP provision and/or bilateral contracts would seem the most appropriate options. However, as identified in the Consultation Paper, a combination of complementary procurement options may lead to the lowest cost. It is important that all options are considered for the provision of these services, including utilising existing assets and allowing more parties to provide services.

DNSPs, particularly where they, like Ausgrid, have dual function assets and a sub-transmission network, can provide system strength services and being allowed to offer such services will support efficient market outcomes. This is already true today and will increasingly become the case as DNSPs develop new capabilities and increase their ability to flexibly manage capacity and voltage within their networks.

4. Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?

We agree with the ENA's submission that robust cost benefit analyses are required throughout the transition and that investments should only be made when there is clear customer benefit. With appropriate governance in place, a level of regulatory flexibility is important to ensure AEMO, TNSPs and DNSPs are allowed and encouraged to evolve to ensure the efficient use of shared network assets across Australia. It is also vital that appropriate investment signals are maintained to support networks developing these capabilities.

Section 7 - Scheduling and Ahead Mechanisms - Market Design Initiative D

1. The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?

No comment.

2. The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?

Yes, Ausgrid supports the UCS concept and agree that there is value in developing better analytics and voluntary ahead mechanisms to improve AEMO's ability to address shortfalls ahead of time.

3. The difference between actual and forecast residual demand leading up to real time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real time dispatch. What do you consider the drivers of this may be?

No comment.

Section 8 - Two-Sided Markets - Market Design Initiative E

1. What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?

As Australia's electricity becomes increasingly sourced from variable renewable generation it will become paramount to unlock the flexibility in the demand side to better match the supply of energy. Although storage will play a pivotal role in addressing this imbalance, most of the value will be unlocked by shaping the demand curve to take advantage of times of cheap and abundant supply of energy. As such, flexible demand is a key enabler of a renewable, reliable, and efficient energy system.

However, significant investment in new markets and frameworks could potentially add to the cost of the system, with little customer benefit. Although new markets, frameworks and solutions are clearly necessary, it is not a given that DER will actively participate in markets once they are created (or evolve). It is therefore important that these developments happen in the context of robust market research and improved forecasting, including understanding consumer preferences and societal trends, monitoring of local and international technology developments, and promoting innovation, standards and flexibility ahead of full-scale implementation. There is also the need to carefully consider the impacts that any new markets or frameworks would have on any existing markets or frameworks before implementing them to ensure that they do not degrade or diminish their effectiveness.

Even then, some backstop measures and regulatory controls will likely continue to form part of the mix of solutions. It is important that a blended approach of market, regulatory and standard based approaches are pursued, with the degree of regulation proportionate to the market failure. These should not be viewed as discrete options to select between, but as a suite of complementary measures to ensure a reliable, clean and affordable energy system for all.

2. What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?

These are well covered in the Consultation Paper.

3. Do you think any other near-term arrangements or changes to the market design can be explored in this workstream?

As identified in the Consultation Paper, regulatory frameworks may need to be adapted to unlock the value from shared community resources. Through our Network Innovation Advisory Committee (NIAC) we are collaborating with customers on a project to investigate the potential for locally based community batteries, paired with innovative business models, as an alternative to traditional local network investment. Our aim is to introduce a novel way to markedly improve equitable access to energy storage for customers and communities while utilising the capabilities of batteries to increase network hosting capacity. A new form of 'distributed governance' by increased community participation in determining the size and technical parameters of the local shared community resource would likely emerge.

The proposed trial consists of a portfolio of community batteries in constrained parts of the network, offering local customers storage as a service to facilitate self-consumption of excess PV energy and exploring commercial arrangements with market participants to utilise

excess storage for wholesale market trading, delivery of frequency control and other grid support services. Community batteries may also provide us with new ways of meeting load shedding directions and NSP underfrequency protection obligations that support the stability of the system.

4. What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?

Central to optimising the benefits of DER and ensuring consumers can participate and engage in a two-sided market offering is ensuring that DER is integrated effectively and efficiently into the network. The key challenge in this regard is ensuring that expenditure to facilitate DER integration delivers service levels in line with customers' expectations and is no more than customers are willing to pay for this investment. This requires regulatory settings that provide NSPs appropriate incentives to efficiently invest. Technical challenges include maintaining grid reliability, minimising voltage fluctuation, facilitating equitable access to exports, enabling new solutions like batteries and virtual power plants to be used for network support and system services, including system strength.

There is also a need to ensure:

- that customer installations meet **minimum standards** that enable devices to be efficiently and effectively orchestrated—to ensure the efficient and effective aggregation and orchestration of DER, interoperability functions including internet connectivity will be required. In addition to allowing DER to be aggregated, this would assist with enabling remote setting management and confirming of inverter settings.
- fit for purpose and secure **communication protocols**—these protocols should include a minimum level of encryption and be a proven and recognised industry standard protocol (e.g. DNP3). Although flexibility is necessary to allow for innovation, the more that vendors create their own bespoke protocols, the harder integration and ongoing management of DER will become.
- discovery and self-registration of DER, appropriate levels of **visibility** and active management capabilities, as well as consideration of the need for trust sharing and device authentication methodology.
- a framework developed around the **roles and responsibilities** in relation to these functions or capabilities in either specific or general circumstances.

In this regard, we note our support for the ESB's recent rule change request to give AEMC the power to set minimum DER technical standards with the support of a technical committee.

In addition, we refer to our answer to question 3 in Section 9 below on the role of an appropriate ecosystem of incentives to drive innovation and participation.

5. What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?

As per our answer to question 1 in this section, it is important that we mature our understanding of existing and future consumer preferences and societal trends, and local and international technology developments. These factors will provide insights into the forecast level of responsive DER and the likelihood of customers (or their agents) enrolling DER in market.

It is likely that there will be regional differences in these factors, and we see a role for DNSPs supporting AEMO to build on the ESOO forecasting work to incorporate these considerations.

6. The ESB is considering combining the DER integration (below) and two-sided markets workstreams, or elements thereof, do stakeholders have suggestions on how this should be done?

If combined, it would still be of value to distinctly consider how to facilitate demand response in NEM spot markets and ahead mechanisms as a discrete objective within a set of DER integration objectives.

Section 9 - Valuing Demand flexibility and Integrating DER - Market Design Initiative F

1. Are there any key considerations for the incorporation of DER into the market design that have not been covered here? For DER to participate in markets, it needs to be responsive. How should the Post-2025 project be thinking about enabling responsive DER?

Although we support the principle of technology neutrality, we also agree with the ESB that considering the nature of DER capabilities may provide useful insights into how to integrate that DER into the system. Rooftop solar can be configured to help its own integration into the system (by for instance riding through disturbances), however the main service provided by rooftop solar to the market is the supply of clean energy. By contrast, flexible demand can provide services needed in response to the uncertainty and variability of renewable generation. It may be more appropriate to integrate passive solar through a combination of technical standards, regulation and cost-reflective pricing, and to focus dynamic network pricing and markets on stimulating flexible demand.

2. In the next phase of the project the ESB proposes to focus on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? The ESB is considering combining the DER integration and two-sided markets workstreams, or elements thereof, do stakeholders have suggestions on how this should be done?

Shared definitions of ‘distribution-level’ markets may aid in progressing the national debate by providing the clarity required to define roles and responsibilities of players within the end-to-end supply chain. Some suggested definitions (these do not represent Ausgrid preferences, but rather an attempt at a comprehensive list of market ideations):

- **Nested Energy Markets** – co-optimisation of services within an area through a local market with a prequalified aggregated bid stack per transmission bulk supply point passed into the wholesale market, with the bulk supply point acting as the wholesale market connection point.
- **Local Energy Trading (P2P)** – local energy flows below a defined point in the system are traded and settled between customers through a trading agreement. These customers do not necessarily satisfy all their energy needs through local trading and still rely on the wholesale market, but their locally traded energy flows are netted off from their wholesale profiles. Multiple P2P markets may exist within the same distribution network.
- **Flexibility Markets** – distributed resources within a specified service area bid in to provide flexibility to alleviate a forecast network constraint (capacity or voltage). This could be well in advance with medium term contracts (e.g. 6 months ahead with a 4-year contract term) to avoid network augmentation or on a dynamic basis as a short-term constraint arises due to contingency conditions (such as an outage). This is similar to the flexibility markets emerging in the UK.
- **Network capacity trading** – customers trading access/capacity rights (such as allocated operating envelope) within a local network area.
- **Locational system services** – auction-based procurement or ahead mechanism for system services within a specified region with a forecast short-fall. As noted by the ESB and FTI, due to the locational nature of these services, competition may not exist to support this.
- **Network configurations with market implications**:
    - **Microgrid** – a part of the network below a defined point that are self-sufficient enough to isolate from the main grid for periods of time (such as during a storm or bushfire event), however these microgrids benefit from maintaining a connection with the NEM to provide and receive services at other times.
    - **Stand-alone power systems (SAPS)** – remote areas of the network that self-sufficient and not connected to the main grid. These networks may benefit from local trading schemes to improve the viability of being supplied by renewable generation.
    - **Embedded Network** – a private network with a single connection point with the local distribution network and the NEM.

These markets and frameworks can, for the most part, co-exist with each other as well as with existing and future wholesale markets and services. These markets also do not have to be facilitated by the same entity and may not be needed in all locations. For example, a Flexibility Market may be facilitated by the local distribution network with a specific need within a specific area and a Local Energy Trading scheme may be facilitated by a peer-to-peer platform provider selected by a local community.

This list demonstrates the importance of:

- introducing flexibility into the definition of a connection point (these may not be the same point for the wholesale market and the local distribution network),

- increasing the sophistication of metering, market settlement processes and trading relationships,
- establishing a framework that enables multiple markets to co-optimise.

We agree with the ESB's views on the role of networks, including the need for increased visibility, building real-time forecasting capabilities and developing dynamic operating envelopes. As a DSO we will also increasingly use market-based approaches to address network constraints, manage access and allocate capacity in the network. Network businesses need to start developing and trialling these capabilities now. It is important that we are allowed and encouraged to evolve to ensure efficient use of the shared network assets in Australia. We recommend that multiple models are trialled concurrently to inform future reforms by rapidly advance our understanding of what works (and what doesn't work).

3. How can we ensure that owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?

We refer to our answer in relation to question 4 in Section 8. In addition, increasing retailers/traders' exposure and/or access to more dynamic cost reflective pricing signals is a necessary precondition to stimulate innovation as it will unlock value streams for customer DER. In this way, an appropriate 'ecosystem' of incentives (i.e. market and network pricing signals) will create the business case needed to invest in increasing flexibility within the system. A 'representative' residential customer in NSW's bill[1] was 34% distribution costs and 36% wholesale energy costs in FY19. To drive an efficient system both these pricing signals need to be in the market.

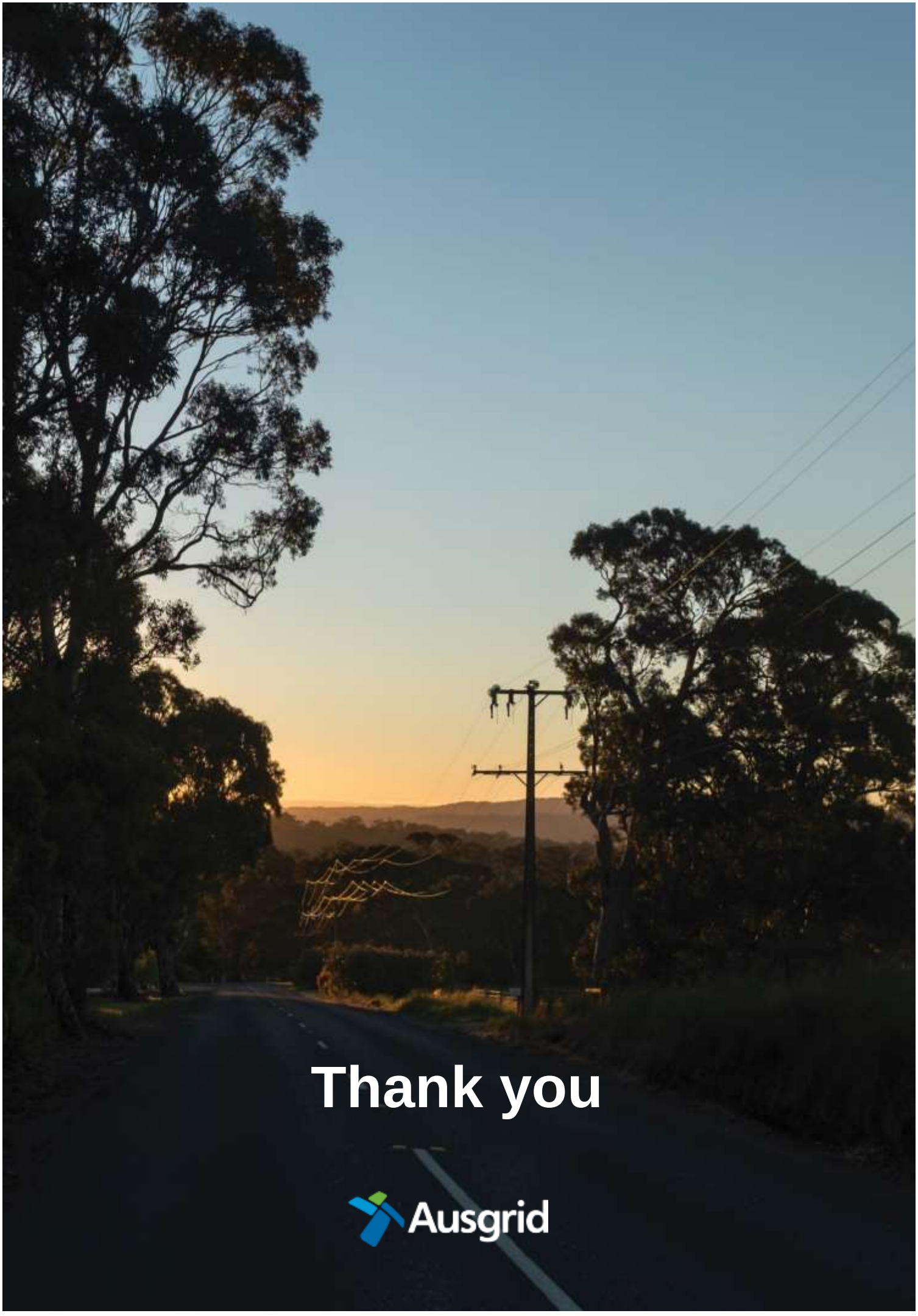
However, these signals do not necessarily need to reinforce each other. For example, a flexible commercial customer may receive a pricing signal from the market that encourages them to increase load in the middle of the day, however the commercial customer may also be within a part of the network that experiences peak load in the middle of the day (such as an office building within a CBD) and the network pricing signal may discourage that customer from bringing on additional load. Provided that both pricing signals are efficient then the customer (or their agent) will rightly weigh these two factors when deciding whether to increase their load.

It is important that network pricing is reflective of network costs, providing efficient price signals to customers or their retailers for network use. Although network tariffs should not unnecessarily hinder wholesale energy market outcomes, network tariffs should not be used to signal wholesale market issues. With wholesale market spot price signals generally more volatile and driven by various external factors, there will be times when these signals won't align with network price signals. A customer's ultimate decision will depend on the relative strength of each.

[1] See AEMC, Residential electricity price trends 2019, Final report, 9 December 2019, page 7

Section 10 - Transmission Access and the Coordination of Generation and Transmission - Market Design Initiative G

How network congestion is addressed at Transmission level could provide valuable insights on how this could be done at the Distribution level. Key pillars of Ausgrid's strategy to integrate DER are tariff reform and innovative access products. Locational pricing and new access products may have a role to play at the transmission and distribution level in the medium to long term.


Thank you
Ausgrid