CLEAN ENERGY COUNCIL

19 October 2020

Dr Kerry Schott AO
Independent Chair
Energy Security Board

Lodged by email: info@esb.org.au

Dear Dr Schott,

POST 2025 MARKET DESIGN – CONSULTATION PAPER

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia. We represent and work with hundreds of leading businesses operating in renewable energy and energy storage along with more than 7,000 solar and battery installers. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

The CEC welcomes the opportunity to comment on the Energy Security Board's (ESB's) Consultation Paper in relation to the post 2025 market design work program. We acknowledge the significant amount of work undertaken to date by the ESB and market bodies to progress its thinking in relation to each of the market design initiatives (MDIs). We also appreciate having been involved in deliberations to date through the ESB's post 2025 market review advisory panel and technical working group. With the Australian Energy Market Operator's (AEMO's) 2020 Integrated System Plan (ISP) and Renewable Integration Study suggesting that renewable energy penetrations of 75 per cent and above may be possible as soon as 2025, it is encouraging that the ESB is actively pursuing measures to facilitate the transition through the suite of potential market reforms. Consequently, the CEC broadly supports the high-level directions outlined in the Consultation Paper, noting significant detail still needs to be developed in relation to the potential design elements. The exception to this, however, is in relation to the transmission access MDI. We do not support continued development of the Australian Energy Market Commission's (AEMC's) current transmission access reform proposal to introduce locational marginal pricing (LMP) and financial transmission rights (FTRs).

The CEC considers two overarching principles are appropriate for the post 2025 market design process to guide the continued development of the MDIs. Firstly, MDIs should promote a lower emissions future through encouraging the entry of new capacity rather than prolonging the operation of existing ageing capacity. MDIs should not seek to entrench revenue streams for incumbent thermal generators. To do so would be to the detriment of consumers as it would discourage new, more responsive, more flexible and lower cost technologies from entering the market, which are needed to reduce costs and improve reliability and security. In the absence of a long-term emissions goal or specific decarbonisation reference within the National Electricity Objective, this may be problematic.

Secondly, there is a potential that the post 2025 market design work program could lead to a number of new interrelated design features and new markets in the National Electricity Market (NEM). Uncertainty tends to spook investors and new entrants or at a minimum requires increased returns on investments, which will increase costs. The complex and interrelated nature of these changes naturally increases uncertainty. The ESB should be mindful of this and aim for simplicity as much as is possible.

The remainder of this submission discusses the CEC's perspectives on each of the MDIs.

Resource adequacy mechanisms

The CEC understands this MDI is concerned with whether the current NEM design provides sufficient signals for investment in firming or dispatchable plant to maintain resource adequacy over the planning timeframe. We generally support the ESB's approach to explore resource adequacy mechanism (RAM) options that sharpen real time prices and long-term investment signals. We are concerned, however, that this MDI is the most likely to entrench revenue streams for incumbent thermal generators, which would unnecessarily prolong their operation. The ESB should be mindful of this in the next steps of design development to ensure that the RAM does not become a captive revenue pool for the ageing thermal generators that would otherwise naturally retire as we transition to a lower emissions system. In addition, any RAM should not seek to weaken the price signals in the current energy only market design.

The CEC supports more detailed exploration of an operating reserve mechanism to complement the work being done to value unpriced services and to make demand more responsive to supply. An operating reserve could reward flexibility to ensure reliability is maintained in an energy system with a high level of renewable energy penetration. Significant detail needs to be developed in relation to such a mechanism. This should include consideration of whether a longer duration hedge or derivative product is also required. A hedge or derivative product may assist the investment case for new flexible generation sources as it could provide developers improved certainty of operating reserve revenue over a longer period of time.

In relation to a potential expansion of the Retailer Reliability Obligation (RRO), the CEC cautions that the market has had little experience with the RRO to assess its effectiveness as a reliability measure. In addition, governments continue to revise the RRO, most recently through amendments announced by the then COAG Energy Council following its March 2020 meeting.[1] We are not convinced that there is a pressing need for a further expansion of the RRO nor an evolution to a decentralised capacity market. It may be more appropriate to allow some experience with an unchanged RRO in the first instance.

Government announcements in relation to reliability are the biggest challenge to resource adequacy.[2] The risk of government intervention undermines investor confidence, which jeopardises the ability for

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[1] COAG Energy Council, Meeting Communique, 20 March 2020. http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/EC%20-%20communique%20-%2020200320.pdf

[2] A recent example is the Federal Government's announcement that it would give the private sector until the end of April 2021 to reach final investment decisions on 1,000 MW of new dispatchable generation capacity (later downgraded to 250MW) otherwise it would step in to build a new gas-fired power station in NSW (see https://www.afr.com/politics/federal/morrison-steps-on-the-gas-20200914-p55val).

the market to deliver new generation investment in a timely manner. Unfortunately, it may not be possible to avoid government intervention given individual governments have specific views and priorities in relation to resource adequacy needs. Providing governments confidence that the RAM can meet their reliability priorities will be key to the maintenance of a consistent approach across all the NEM. While we would prefer this is avoided, jurisdictional amendments to how the NEM-wide RAM is applied in a jurisdiction is preferred to separate, direct government interventions in the market.

Critical to the success of this MDI is a recognition that different types of storages will play a key role in a future low emissions system. The next step of MDI development should investigate the linkages between capacity and duration and how RAMs can ensure a good balance of shorter duration batteries and longer duration pumped hydro.

We note the discussion in the Consultation Paper has not directly considered the potential cost to consumers of the potential RAMs. It is important that this is addressed in the next steps of the design development, particularly as increased reliability requirements will come at an additional cost.

In the next stage of work on this MDI, the CEC also suggests the ESB should explicitly consider how a RAM can support innovation and competition. This should contemplate the role of distributed energy resources (DER) in the delivery of resource adequacy. While DER may not be able to effectively participate in RAMs from the outset, DER is a growing segment within the NEM in terms of both size and sophistication. A RAM should be able to evolve to allow aggregated DER participation at some point in the future. Similarly, the next stage should also contemplate the participation of demand response in the RAM.

Ageing thermal generation strategy

The CEC appreciates there are government, market and consumer concerns regarding the cost, reliability and security impacts if sufficient replacement capacity and system services are not available in a timely manner to replace large, ageing thermal generators as they exit the NEM or become unavailable at critical times. The market clearly wants to avoid a similar situation to that which occurred with the sudden closure of the 1,600MW Hazelwood Power Station.

Since Hazelwood's closure, a number of initiatives have been introduced to reduce the risks associated with thermal generator exits and better inform the market of the need for new generation investments to maintain reliability. These include the establishment of the notice of closure requirements and RRO, and improved NEM planning, particularly through the ISP.

This MDI clearly links with the work being undertaken on RAMs, essential system services and two-sided markets. The CEC supports the ESB's approach for this MDI that it should consider whether there are residual risks relating to ageing thermal generators exiting and if additional measures are needed to address these beyond potential reforms being progressed through other MDIs.

The CEC proposes that the work done on this MDI should aim to make a decision on how the market should function that provides comfort to governments and market bodies in order that they will adhere to that decision. Knee-jerk reactions to new information about potential thermal generation closures should be avoided. This should also recognise that while dramatic saw tooth wholesale price movements result in costly consumer outcomes, we should not seek to extinguish all price movements completely as these provide a natural signal of the need for investment in new capacity.

Whilst we acknowledge there is a need for certainty around generator closures, the CEC also suggests that the ESB should consider how flexibility can be provided in relation to the notice of closure requirement in order that thermal generator closure dates can be brought forward in an orderly manner as the market evolves. This approach recognises that the market should be encouraging new renewable energy generators coupled with firming through utility-scale batteries or pumped hydro to enter the market as the cost of these technologies will continue to fall such that they will be lower cost compared with the continued operation of existing coal-fired generators. Bringing these technologies into the market in a timely manner is needed for improved consumer outcomes.

Similar to the RAM MDI, the work on ageing thermal generation strategy should not look to delay the natural exit of ageing coal-fired generators.

It may be helpful for the ESB to consider further improvements to market information as part of this MDI. We have already mentioned improved planning information through the ISP. However, the ISP is a least cost approach that assumes coal-fired generators will exit at the end of their technical life or earlier if a generator has made a public announcement of its intended closure date. The ISP does not assess whether it might be economic to replace coal-fired generators sooner than this. Evolving the ISP to consider this scenario could unlock the benefits of new renewable energy generation and storage and could assist transmission and new generation planning and investment.

It may also be appropriate to have an ongoing market monitoring arrangement that assesses the pressures and economic risks on existing ageing generators. This could be part of the ISP or done separately.

Essential system services

With the progressive evolution of the NEM to one that is lower emissions, it is timely to consider how essential system services can continue to be delivered to ensure system reliability and security are maintained given a number of services are not valued discretely at present. The Consultation Paper explains the ESB's preference to move towards real-time markets for services where the system and technologies allow but that some services (particularly system strength) appear better suited to structured procurement arrangements. As a result, the ESB suggests it will explore options for:

1. Operating reserve procured by a spot market with a demand curve framework, with possible additional mechanisms to support investability.
2. Developing arrangements to incentivise primary frequency response ahead of the mandatory primary frequency response sunset in 2023.
3. Supporting the provision of fast frequency response within the existing NEM framework.
4. Supporting ahead-scheduling and coordination of the provision of inertia and system strength, alongside structured procurement arrangements.
5. A spot market for inertia in the post-2025 NEM, with co-optimisation with frequency control and operating reserve, with a view for implementation in the medium term.

The CEC broadly supports this approach, noting significant work is still required to develop the detail of the procurement processes. This aligns with our position outlined in our submissions to the AEMC's consideration of the mandatory primary frequency response rule change proposal, investigation into system strength frameworks in the NEM and consideration of the six system services rule change proposals.[3] In these submissions, we have advocated for:

- Urgent revision of the system strength frameworks given system strength issues are emerging across all NEM jurisdictions and the 'do no harm' requirement as part of the generator connection process is leading to substantial uncertainties, costs and delays to new projects as well as inefficiencies across the market through the proliferation of individual synchronous condensers. As a result, we strongly support structured procurement of system strength through Transmission Network Service Providers (TNSPs).
- Establishing a fast frequency response market ancillary service to recognise the speed, accuracy and quality of frequency response that technologies such as batteries can provide to support the transitioning power system.
- Establishing a market-based approach for primary frequency response to replace the current mandatory primary frequency response requirement.

The CEC can understand the ESB's attraction to moving across the procurement options for essential system services given academically, spot markets deliver the clearest price signals. However, we caution that any evolution along the spectrum needs to ensure the additional complexity is justified and competition concerns are avoided. It should also consider whether hedging products would be necessary.

The CEC agrees with the ESB's assessment that there are challenges associated with moving to a spot-market based approach for system strength, particularly given its localised nature. The ESB should be mindful of the potential impacts moving to a spot market or even the potential of moving to a spot market may have on system strength contracts procured by a TNSP and the ability to invest in long-term system strength assets. Given this, we recommend against defining any sort of timeframe for a review of the potential to move from structured procurement to a spot market for system strength.

There is an interaction between inertia (including synthetic inertia), primary frequency response and fast frequency response as all reduce the rate of change of frequency following contingencies. As a result, further development of this MDI will need to closely examine this interaction and consider whether the existence of one market could degrade the efficiency of another. In spite of this, the CEC considers the introduction of a fast frequency response market consistent with the existing frequency control ancillary services regime as a no regret option.

Given essential system services are currently provided as a by-product of energy by thermal generators, the CEC reiterates our earlier comment that further development of this MDI should be mindful to avoid entrenching revenue streams for incumbent thermal generators that would otherwise naturally retire as we transition to a lower emissions system.

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[3] AEMC, Mandatory Primary Frequency Response Rule Change, Draft Determination submission: CEC, 14 February 2020. https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_erc0274_-_clean_energy_council_-_20200213.pdf
AEMC, Investigation into System Strength Frameworks in the NEM, Discussion Paper submission: CEC, 7 May 2020. https://www.aemc.gov.au/sites/default/files/documents/cec_response_to_aemc_system_strength_investigation_discussion_paper_200507_final.pdf
AEMC, System Services Rule Changes, Consultation Paper submission: CEC, 13 August 2020. https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_clean_energy_council_-_20200813_-_erc0263_erc0290_erc0295_erc0296_erc0300_erc0306_erc0307.pdf

The next stage of development will need to consider cost recovery mechanisms. It is appropriate that causer-pays and beneficiary-pays approaches are explored. For structured procurement of essential system services through TNSPs, a hybrid cost allocation consisting of a consumer charge and generator charge may be appropriate. The clean energy industry would prefer that if there is to be a generator charge, this charge should be identified early in the connection process, such as at the connection enquiry stage of the project. The charge must also be predictable and simple to understand to avoid adding investment risk to projects. Generators should retain the flexibility to negotiate with the TNSP on how the charge is allocated to them as either an upfront capital cost or annuity. A charge akin to a generator transmission use of system charge that may fluctuate over the life on an asset should be avoided as the uncertainty alone of this cost will increase the effective cost of energy delivered from future, capital-intensive generation projects.

As with the RAM MDI, it is imperative that the essential system services framework is flexible to allow DER and other new technologies to provide services where and when possible.

Scheduling and ahead mechanisms

The CEC appreciates that uncertainty and variability in the NEM are increasing, which is leading to greater complexity for the system operator. In response, the Consultation Paper explains that the ESB considers there is a need for greater visibility of the resources available in the system in order to support the ability to achieve real time economic dispatch of the system and reduce reliance on operator intervention into the market to assure system security and reliability.

The CEC supports the ESB's intended direction for this MDI. We support in principle the development of a Unit Commitment for Security (UCS) approach to support scheduling system services under contract and systemise how AEMO issues directions to market participants. There is clearly significant detail around the UCS that still requires development.

We also support the ESB's decision to not proceed with further consideration of a compulsory ahead market design as this would limit flexibility and moves away from the self-commitment nature of the NEM. A compulsory ahead market would not be a proportionate response to the identified problem.

While a voluntary approach as envisaged under option 2 (system service ahead scheduling) and option 3 (integrated ahead market) may appear to have academic merit, it is difficult at this stage to see how these would work in practice given they would likely entail substantial operational complexities in order to participate. It is even uncertain whether participants would be able to find suitable counterparties thus creating some doubt as to whether sufficient liquidity would arise in these voluntary markets. Any consideration of voluntary markets would need to overcome these practical questions and also ensure that a cost-benefit assessment is satisfied.

There is significant congruency between this MDI and the essential system services MDI. This necessitates that this MDI is implemented in parallel with the procurement options under the essential system services MDI.

Two-sided markets

The CEC broadly supports the intention to move towards a two-sided wholesale market as we believe that greater flexibility in the market and improved visibility of the demand side of the market will complement a future NEM alongside renewable energy generation, energy storage, stronger interconnection and energy efficiency. We see the move to a two-sided market as the next step following the implementation of the Wholesale Demand Response Mechanism.

The CEC agrees with the proposed benefits provided by the transition to a two-sided market presented in the Consultation Paper. In particular, the opportunities presented through the continuing technological advancements in the demand side of the market are significant. Integrating the demand side of the market into the wholesale market will provide the market operator with additional mechanisms to manage the variable nature of renewable energy.

Technology is rapidly transforming the capability of the demand side of the market. Markets typically lag what is technically possible. Demand-side markets are no exception. We would urge the ESB to ensure that market reforms might move with technology.

The participation levels required by the market will be critical to ensuring the immediate and long-term success of a two-sided market. We agree with the ESB that the long-term goal of the two-sided market should be full participation of all participants. Although requiring full participation in the short term is unlikely to result in the most efficient implementation, the ESB should create pathways for full DER participation as an option. The CEC proposes that selective participation be the starting point for a market transition to becoming two-sided. This would enable a significant portion of the demand-side market that is likely to be technically capable to begin to participate. Provided the incentives are appropriately structured, this approach would also allow for the small-scale segment of the demand market to participate. Selective participation could see rapid innovation in the small-scale consumer sector as the market pushes to capture the benefits of the transition to a two-sided wholesale market. Technically, most contemporary DER hardware is already capable of participation in a two-sided market (although vehicle to grid technology requires further development). However, without clarity on the architecture of the market, it is too risky for any player to build out the interfacing software that enables the DER to integrate at scale into NEM markets. The obligation on the ESB is to create that architecture. Then any missing technology can be developed.

Incentive structures will be critical to guiding the transition and success of the implementation of a two-sided market. In principle, the requirements on both the demand and supply sides of the market should be created fairly and equally as they both have the potential to impact the stable operation of the system. We also recognise that the level of control of demand bids to meet dispatch targets may not wholly rest with those placing the bids, as is the case for the supply side. The incentive stricture should be proportionate with the value created or lost in the market through compliance or penalties for deviation with dispatch targets. For voluntary participants, there will need to be careful balance between discouraging participation and encouraging conforming with targets.

There is potential for improvements to the forecasting processes and requirements applied to scheduled participants compared to the current arrangements. The long-term aim should be for similar requirements for scheduled participants on both sides of the market. However, in the beginning and while transitioning to a two-sided market, this approach will not be practical due to the technical limitations in the forecasting ability of some participants. The value in this information from scheduled participants in the demand side will be reliant on the accuracy of the information. The accuracy of the information provided into these processes will be reliant on the monitoring and verification framework.

Valuing demand flexibility and integrating DER

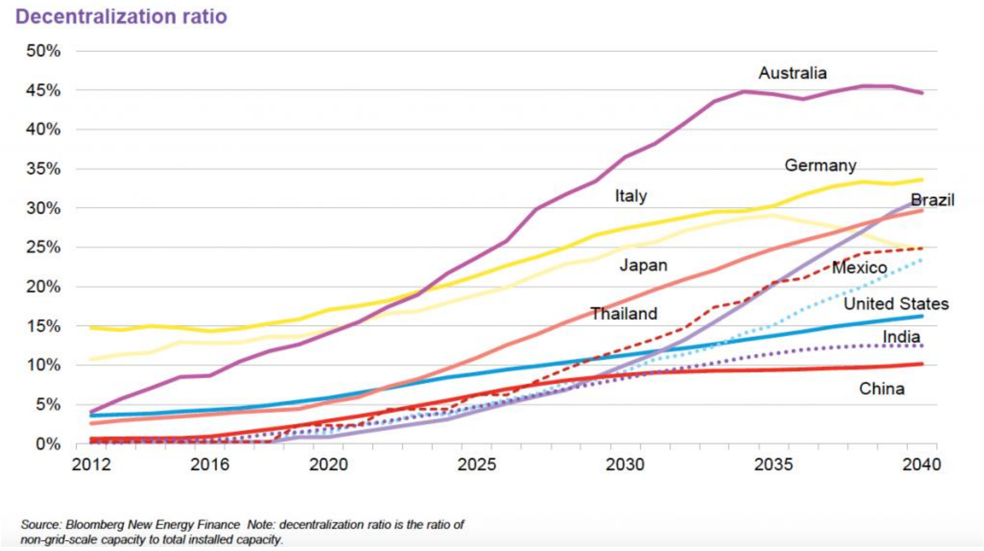
The CEC appreciates the focus of the Consultation Paper concerning DER. While it is the least developed part of the Consultation Paper, we believe it covers most of the important considerations with respect to enabling responsive DER to participate in a range of wholesale and distribution level markets. Importantly, the paper begins to address a much-needed void in the DER work advanced to date which has largely focused on technical and regulatory matters. Compared with international efforts, Australia has had a seriously inadequate focus on the valuation and remuneration of the valuable grid-services that DER can provide.

As such, we believe the Consultation Paper provides an important step toward our ambition to see

> *"DER services valued and enabled as essential to optimising Australia's future electricity system and delivering efficient outcomes for society, households and business."*

Given the world-leading pace and scale of Australia's current transition and the projections that our electricity systems will become some of the world's most decentralised (refer Figure 1 below), this type of ambition is critical to Australia's future.

Figure 1: Decentralisation Ratio



In supporting what is a valuable ESB initiative in this complex area, the CEC believes there are some additional elements that should be considered in the next phase of the post 2025 work program. These include (and are expanded on further below):

A. Provide a vision and targets for the participation of DER in markets
B. Tariff reform and smart meter rollout
C. The framework for investment by Distribution Network Service Providers (DNSPs) in communications infrastructure
D. Strategies to build consumer understanding of these markets and to encourage participation
E. Governance of regulation of communications infrastructure and related protocols
F. Governance of regulation of voltage management on the low voltage distribution network
G. Improving compliance and enforcement

H. Removing barriers in grid connection rules that limit battery installations
I. Development of connection agreements for dynamic engagement of DER
J. Resolution of the tensions between market actors which impede progress regarding the roles of the Distribution System Operator (DSO) and Distribution Market Operator (DMO)
K. The system architecture enhancements required to enable Australia's future grid at least cost.

It is also important to note that there is a large legacy fleet of solar PV systems that will not be automatically optimised for participation in future markets. However, while product standards do not apply retrospectively, there is an opportunity to ensure such systems can participate when they are upgraded or when say an inverter is replaced. Indeed, the opportunity to participate in relevant DER markets is the single best way to motivate a large volume of owners to enable their DER to provide grid-services that benefit all customers in exchange for a share of the financial value. This will also ensure that there are incentives for solar PV owners to add a battery and use it to participate in markets. Noting that there are some unnecessary barriers, especially in grid connection rules, that prevent this from happening, the removal of barriers to battery retrofits should be a high priority for regulatory reform.

A. Provide a vision and targets for the participation of DER in markets

The widescale enablement of DERs to support the electricity system represents one of the most fundamental challenges in the ESB's post 2025 work program, and one of the most significant opportunities in the Australian energy landscape.

We believe that it would be valuable for the ESB to adopt a guiding vision or statement of ambitions – possibly in a form similar to that defined by the CEC – as a guiding light for long-term market reforms:

> *"DER services valued and enabled as essential to optimising Australia's future electricity system and delivering efficient outcomes for society, households and business."*

In addition to this, we would recommend that the vision be supported by a statement of measures of performance and targets through the years for DER participation in markets. This then can act as a guide to ambition and its achievement.

B. Tariff reform and smart meter rollout

The Consultation Paper only considers tariff reform insofar as it applies to DER. This is insufficient. Optimising DER integration will require tariff reform for all customers, not just DER customers.

The key barrier to tariff reform for all customers has been the failure of the Power of Choice approach to the rollout of smart meters. Uptake of smart meters has been very low except where it has been mandated (e.g. for PV installations and new connections).

By overlooking this important policy reform area, the post 2025 market design work seems to implicitly assume that the problems of smart meters, tariffs and the failure of Power of Choice reforms will be fixed before 2025. If this is the assumption underlying the post 2025 market design, it should at least be stated explicitly. The ESB could also consider whether the Power of Choice approach to the rollout of smart meters is satisfactory and if not, what changes should be made.

C. The framework for investment by DNSPs in communications infrastructure

The Consultation Paper acknowledges the critical importance of communications infrastructure for enabling DER integration. Recent proposals by AEMO regarding remote curtailment of DER to support system security have raised questions about the variety of potential communication technologies that could be used for that purpose. Decisions will be required to select the appropriate communication technology. Decisions are needed on the required level of communication performance (e.g. reliability of curtailment and latency) which will affect technology choices. There does not appear to be a framework for investment in communications infrastructure and we understand that this is not part of DNSPs' regulatory proposals for the period to 2025.

The CEC recommends the ESB consider whether any rules changes are required to set outcomes and responsibility for investment by DNSPs in communications infrastructure.

D. Strategies to build consumer understanding of these markets and to encourage participation

The value of each individual action that a given DER can take to support markets will be small and indeed, it will only be in large-scale aggregation that there is any significant value. Further, energy market participation is not the driving rationale for people to own DERs.

Therefore, the CEC believes it will be important to have strategies designed to enhance the awareness of consumers and their agents about the opportunity to participate in energy and grid markets. These strategies will help to improve the 'thickness' of DER markets and in turn reward efforts in creating them.

E. Governance of regulation of communications infrastructure and related protocols

Communications infrastructure and protocols will be increasing important in future as we move toward a more interconnected network of DER assets. There is a danger that DNSPs and jurisdictions could set different requirements creating 'rail gauge' issues. Already the South Australian government has set its own requirements for internet connectivity and the Victorian government is considering internet connectivity rules for DER. It would be helpful for the ESB to consider an overarching approach to governance of the communications infrastructure and related protocols before we must respond to a variety of communications standards and protocols set by jurisdictions and DNSPs.

F. Governance of regulation of voltage management on the low voltage distribution network

Voltage management on low voltage networks is a key component of the provision of 'export services' and 'hosting capacity'. The AEMC is currently considering several requests for rule changes that are essentially proposing a national, pricing-based approach to voltage management which would be overlaid on a state and territory regulatory approach. It is unclear how the division of regulatory responsibilities would work in practice with regulation of voltage management remaining at the level of state and territory regulators while the AEMC overlays a pricing-based approach for changes at the margin.

There is a regulatory requirement for DNSPs to manage voltage within standards. A report commissioned by the ESB[4] and undertaken by University of New South Wales[5] found that "even in the absence of solar PV, there is a significant level of high voltage across all DNSPs in all NEM states" and "many sites experience higher voltages during the night when solar PV is not operational". The ESB notes that this "appears to point to a material level of technical non-compliance, but this may depend on how the data is viewed and how the respective standards are applied in each jurisdiction".

Table 1 summarises the governance of regulation of voltage management in Australian states and territories.

Table 1: Governance of regulation of voltage management

Jurisdiction	Regulator	Regulatory head of power
Australian Capital Territory (ACT)	Independent Competition and Regulatory Commission (ICRC)	Independent Competition and Regulatory Commission Act 1997 and Utilities Act 2000
New South Wales (NSW)	Independent Pricing and Regulatory Tribunal (IPART)	Independent Pricing and Regulatory Tribunal Act 1992 No 39 & Electricity Supply Act 1995, National Electricity (New South Wales) Act 1997 No 20 and National Electricity (NSW) Law, Electricity Safety Act 1945
Northern Territory (NT)	Utilities Commission	Electricity Reform Act 2000 and Utilities Commission Act 2000
Queensland	Queensland Competition Authority (QCA)	Electricity Act 1994 and Electricity Regulation 2006
South Australia (SA)	Essential Services Commission of South Australia (ESCoSA)	Essential Services Commission Act 2002 and Electricity Act 1996
Tasmania	Office of the Tasmanian Economic Regulator (OTTER)	Electricity Supply Industry Act 1995 and Tasmanian Electricity Code 2015
Victoria	Essential Services Commission (ESC)	Electricity Safety Act 1998, Electricity Safety (General) Regulations 2019 and Electricity Distribution Code 2020
Western Australia (WA)	Economic Regulatory Authority (ERA)	Electricity Act 1945, Electricity Industry Act 2004 and Electricity Networks Access Code 2004

We have searched the websites of all the regulators in search of a report on their approach to regulation of voltage management. There appear to be remarkably few references to regulation of voltage management. Refer to Attachment 1 for further details. A notable exception is Victoria's Essential Services Commission (ESC) which requires DNSPs to report on how the information from smart meters is being used to enhance the management and operation of the distribution system. The ESC's reporting framework appears to be the most comprehensive in Australia. Outside of Victoria,

[4] ESB, Cover note on the UNSW Voltage Report, May 2020. https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/200502%20ESB%20cover%20note%20on%20UNSW%20Voltage%20Report.pdf

[5] Bruce, A., Heslop, S., Heywood, P., MacGill, I., Passey, R., Stringer, N. and Yidiz, B., *Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market*, May 2020. https://cloudstor.aarnet.edu.au/plus/s/yXM0UFtPMJmWcLe

some states regulators (e.g. the Office of the Tasmanian Economic Regulator) record the number of customer complaints due to voltage issues. See Table 4 on the Attachment for further details.

The post 2025 market design project should consider bringing regulation of voltage on the low voltage network into the National Electricity Rules (NER). Governance of voltage management is currently highly fragmented and is the responsibility of state and territory regulators.

G. *Improving compliance and enforcement*

Rules are only effective when compliance is adequate. The current regulatory framework for compliance and enforcement of some important parts of regulation of DER is piecemeal and could be significantly improved. For example, there is little in the way of inspection and enforcement of power quality settings for new inverters. The Clean Energy Regulator (CER) is proposing to expand its inspection program to include power quality settings. This is an area that could be addressed by taking advantage of internet connectivity of inverters using remote confirmation of settings. At this stage, it is unclear which agency, apart from the CER, has the authority and capability to undertake such a role. It is appropriate that the CER commence this work, however as the incentives under the Small-scale Renewable Energy Scheme (SRES) reduce over time there will be a need to transition the remote inspection role to another agency. The ESB’s proposal to incorporate DER technical standards into the NER could be an opportunity to put in place a long-term governance framework for compliance and enforcement of inverter requirements that can endure beyond the life of the SRES.

H. *Removing barriers in grid connection rules that limit battery installation*

There is a large legacy fleet of DER that will not be optimised for participation in future markets. Product standards do not apply retrospectively. However, there is an opportunity to upgrade the performance and capabilities of DER systems when they are retrofitted (e.g. an expansion of the PV array or the addition of a battery). The single best way to ensure DER owners can optimise the benefits of their assets will be to ensure there are incentives for owners of solar PV systems to add a battery and use it to participate in markets.

Most DNSPs class storage and solar PV separately and apply the standard 10 kVA limit to each inverter separately. This is the preferred approach. However, several DNSPs stipulate grid connection rules that prevent customers from upgrading their system by adding a battery. We understand that Energex, Ergon Energy and Ausnet Services impose a 10 kVA inverter limit, calculated as the sum of the PV inverter and battery inverter capacity for new systems and retrofits. The average size of PV systems installed in 2020 is about 7 kW. When the DNSP limits the total inverter capacity to 10 kVA, this means that the owner of an average-sized PV array can only retrofit a battery of no more than 3 kVA. This is unnecessarily restrictive and is a barrier to upgrading the capability of the existing DER fleet.

There are several ways that a combined solar and battery inverter capacity of more than 10 kVA could be allowed behind the meter without comprising network management. For example, where there is a limit on the combined PV and battery inverter capacities, it could be waived if the DER system is:

- Part of a Virtual Power Plant arrangement, or
- Subject to the terms and conditions of a dynamic connection agreement.

There is also the option of converting a single phase connection to three phase.

The CEC understands that the objective of this review is not to develop a detailed solution to every grid connection issue. At this stage, we are simply suggesting that the review should acknowledge that grid connection rules can present an unnecessary barrier to battery installation and that this is an issue that needs to be addressed. This is a barrier that needs to be addressed sooner rather than later because connection arrangements are a key underlying framework piece for all DER-related market development and some two-sided market work. The longer the existing frameworks act as a barrier for existing solar customers to install batteries, the less controllable DER will be available in the market.

I. Development of connection agreements for dynamic engagement of DER

Connection agreements should allow for the dynamic engagement of DER in the power system and energy customers should have the right to initiate a review of their connection agreement and the opportunity to receive a better deal. Customers on dynamic connection agreements should not have limits imposed on the capacity of DER systems behind the meter.

J. Resolve role tensions between market actors which impede progress regarding the DSO and DMO

The CEC welcomes the ESB's inclusion of distribution-level markets as one of its six key considerations for DER integration in developing a post 2025 market. As noted earlier, this begins to address a much-needed void in Australia's DER work to date which has largely focused on technical and regulatory matters.

Many global jurisdictions are actively engaging with the topic of DSO and DMO as critical enablers of valuing and enabling the full value of DER grid-services. Regrettably however, the Australian market is broadly aware of the tensions between Energy Networks Australia (ENA) and AEMO on definition of, and even the need for, DSO and DMO roles. This appears to have substantively constrained the ability to have a transparent and multi-party engagement on this topic of national importance.

Given the world-leading scale of Australia's DER uptake, this regrettable history needs to be addressed head on. Therefore, the CEC advocates that the ESB proactively establish a pathway to address these critical matters and their systems architecture implications (item K below) as a key priority.

In particular, it is noteworthy that Western Australia's Energy Transformation Taskforce (WA ETT) recently published an Issues Paper on DER Orchestration Roles and Responsibilities.[6] This is important work on definition of orchestration roles in the energy market, including the roles for the DSO and DMO. We suggest the ESB consider the recent work by the WA ETT together with other relevant work underway in North America, the United Kingdom and the European Union. While the NEM has specific and unique requirements, there are many elements of the WA ETT and international proposals with respect to DSO and DMO design that could inform the establishment of distribution services markets in the NEM.

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[6] WA Energy Transformation Taskforce, Issues Paper - DER Roadmap: Distributed Energy Resources Orchestration Roles and Responsibilities, 14 August 2020. https://www.wa.gov.au/sites/default/files/2020-08/Issues%20Paper%20-%20DER%20Roadmap%20%20Distributed%20Energy%20Resources%20Orchestration%20Roles%20and%20Responsibilities.pdf

K. System architecture enhancements required by Australia's future grid

As Australia's electricity system transitions to an increasingly decentralised and decarbonised future, the full potential of new energy technologies will be increasingly difficult and costly to realise. This is because the structure or architecture of a complex system, in this case designed in the 20th century for centralised, one-directional supply, has a disproportionate influence on what the system can efficiently and reliably do.

The ability to efficiently integrate high levels of DER and variable renewable energy is foundational to Australia's 21st century power system. Both can provide a wide range of beneficial, physics-based services to the entire power system. However, enabling these will become increasingly complex and costly without considering the limited but most impactful enhancements to the systems architecture of Australia's power system.

Several other nations are investing heavily to advance such processes although they are yet to experience the scale of large-scale renewable energy and DER-uptake Australia is experiencing. These objective and multi-party processes are analysing how both large-scale renewable energy and mass-deployed DER may be fully leveraged across all layers of their power systems (e.g. wholesale, transmission, distribution, retail, peer-to-peer).

We suggest the ESB consider the systems architecture work underway in North America, the United Kingdom and the European Union as a critical input to enabling deep DER integration and unlocking the full value of large-scale renewable energy and DER grid-services at least cost.

Transmission access and the coordination of generation and transmission

Since before the post 2025 market review process commenced, the AEMC has been developing a model for transmission access reform that is centred around two core elements – LMP and FTRs. The CEC has prepared a detailed submission to the AEMC's Interim Report in which we outline the clean energy industry's concerns with the proposal. We do not support the proposal. We believe it is the wrong reform at the wrong time and that efforts on the model should be ceased in order that AEMC and industry resources can be redirected to more pressing issues, such as other post 2025 MDIs. Recently confirmed elements of the proposed design, such as the movement to dynamic marginal losses with no ability to hedge these losses, advanced sale of FTRs in tranches over a ten year period and pre-defined FTR nodes, have only further compounded our view that the model will provide no investment certainty for generators. We maintain our concern that the transmission access reform proposal will add additional risk, complexity and cost to the market.

To support this, the CEC undertook a survey of our members' expectations of the impacts of the transmission access reform proposal on the cost of capital. This is similar to the investor survey undertaken by the AEMC in 2019. The responses to the CEC survey suggest that the current iteration of the transmission access reform proposal would increase the weighted average cost of capital (WACC) by between 30 and 250 basis points, with an average response of a 137 basis points increase.[7] Notably, respondents indicated a high degree of understanding of the model design, which

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[7] In the interests of transparency, we note that two responses suggested there would be no change to the WACC. Both respondents are vertically integrated market participants with diversified generation portfolios.

suggests that the increased risk premium relates to the model design itself and not uncertainty or a lack of understanding of the design elements.[8]

The CEC suggests other initiatives underway will address congestion and improve locational signalling. These include:

- The ISP and actioning the ISP rule change
- Development of Renewable Energy Zones (REZs)
- Work around a nodal approach to system strength as suggested in TransGrid's rule change and proposed in the AEMC's investigation into system strength frameworks in the NEM
- The transparency of new projects rule change that was finalised in October 2019
- General improved system information, particular through AEMO's Interactive Map.

As a result, some experience with the above initiatives is warranted to better understand the magnitude of any residual issues and therefore whether access reform is still justified. Such an approach would consider whether appropriate alternative options that are not premised on changes to the wholesale market pricing arrangements may be more appropriate.

In relation to REZs, the CEC reiterates our support for REZ development as a means to deliver coordinated and scale efficient network augmentations for new renewable energy generators. We support further investigations into the applicability of either physical or financial access rights for REZs in preference to continued development of the AEMC's whole of system transmission access reform proposal. The CEC looks forward to engaging with the ESB on the second step of its REZ framework development work.

We recommend the ESB review the CEC's submission to the AEMC's Interim Report for more details.

Overall market design

The CEC appreciates that the ESB has recognised the interdependencies between MDIs as well other initiatives currently being considered separately to the post 2025 market review. We support the approach to consider a phased roadmap for long-term reform that is conscious of the congruency between reforms and the evolutionary nature of the MDIs.

We would like to take this opportunity to highlight a critical market issue at present that is overlooked by the post 2025 market review and requires attention. The current process to connect large-scale generators to the grid is leading to increased costs and delays for new developments and therefore increasing the risk in the NEM. As is clear in the survey results of the CEC's recent poll of the challenges facing investors at present (as depicted in the ESB's Consultation Paper), grid connection is the number one issue for the clean energy sector.[9] There is an urgent need to improve this process. Changes to the system strength framework and do no harm requirement as envisaged in the essential system services MDI will improve parts of the connection process. However, more can be done. The

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[8] Survey respondents were asked to rate their knowledge and understanding of the transmission access reform proposal on a scale of 1 to 5 (1 indicating no or very limited understanding and 5 indicating full understanding). The average response was 3.7. This question was not asked in the AEMC's 2019 investor survey.
[9] ESB, Post 2025 Market Design Consultation Paper, September 2020, p. 22.

CEC would be happy to have a more detailed discussion of the issues around grid connections directly with the ESB.

Other issues

The CEC acknowledges the significant amount of work undertaken in recent months on the post 2025 market design and has been fortunate to have been involved in this through the ESB's advisory panel and technical working group. We note, however, that for those stakeholders that have not been involved in these forums, the Consultation Paper has presented a number of new and complex initiatives that they are seeing for the first time. It has been incredibly difficult for these stakeholders to meaningfully engage in the Consultation Paper given the short six-week consultation period at a time when there are a number of other sizeable and related consultation processes underway, such as the AEMC's transmission access reform proposal and integration energy storage systems into the NEM rule change. This is especially problematic for many CEC members as they tend to be smaller organisations that do not have dedicated resources for policy work.

In future, we urge the ESB and market bodies to consider this in their engagement and consultation planning. Longer periods to prepare submissions and staggered submission due dates would certainly help. More regular engagement with stakeholders not involved in the advisory panel and technical working group would also be beneficial. The CEC is happy to assist the ESB with these engagements given our membership is keenly interested and highly supportive of the post 2025 market review.

Thank you for the opportunity to comment on this consultation. If you would like to discuss any of the issues raised in this submission, please contact me, as outlined below.

Yours sincerely,

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Attachment – Governance of regulation of voltage management

Table 2: Jurisdictional regulations for voltage management

Jurisdiction	Regulations/Legislations
ACT	• Independent Competition and Regulatory Commission Act 1997 – Section 4A 4 B provides general information about distribution but provides no information about voltage management. • Utilities Act 2000 – this document has details about distribution but nothing about voltage management.
NSW	• Independent Pricing and Regulatory Tribunal Act 1992 No 39 – No information about voltage management • Electricity Supply Act 1995 – p. 9 107 has a line on the top of the page stating that “standards for the voltages to be maintained at the terminals of consumers of electricity” and contains information throughout the document about distribution • National Electricity (New South Wales) Act 1997 No 20 – No information about voltage management but in general has details about distribution • National Electricity (NSW) Law - No information about voltage management and but has information about distribution throughout the document • Electricity Safety Act 1945 – No information about voltage management
NT	• Electricity Reform Act 2000 – p. 60 has some information about voltage a bit and document in general has details about distribution • Utilities Commission Act 2000 – No information about voltage management
Queensland	• Electricity Act 1994 – In general, document has information about voltage and distribution in great details • Electricity Regulation 2006 – In general, document has information about voltage and distribution in great details
SA	• Essential Services Commission Act 2002 – No information about voltage management • Electricity Act 1996 – Has information about voltage on page 4 and distribution throughout the document
Tasmania	• Electricity Supply Industry Act 1995 – 3A has information about both voltage management and distribution throughout the document in details • Tasmanian Electricity Code 2015 – Distribution – Has information about both voltage management and distribution throughout the document in details
Victoria	• Electricity Safety Act 1998 – Has detailed information about voltage management and distribution throughout document. • Electricity Safety (General) Regulations 2019 – Has detailed information about voltage management and distribution throughout document • Electricity Distribution Code 2020 – Has detailed information about voltage management and distribution throughout document
WA	• Electricity Industry Act 2004 – Has some information about voltage management on page 3 and distribution throughout the document • Electricity Networks Access Code 2004 – Has detailed information about voltage and distribution throughout the document

Table 3: Ministers responsible for regulation of voltage management

Jurisdiction	Responsibility
ACT	Attorney-General - Justice and Community Safety Directorate Minister for City Services - Transport Canberra and City Services Directorate Treasurer - Chief Minister, Treasury and Economic Development Directorate Minister for the Environment and Heritage - Environment, Planning and Sustainable Development Directorate Minister for Climate Change and Sustainability - Environment, Planning and Sustainable Development Directorate
NSW	Minister for Energy and Environment
NT	Minister for Renewables, Energy and Essential Services is responsible for provisions about supply and service provision under licence
Queensland	Minister for Natural Resources, Mines and Energy
SA	Minister for Energy and Mining
Tasmania	Minister for Energy
Victoria	Minister for Energy, Environment and Climate Change
WA	Minister for Energy

Table 4: Reporting by jurisdictional regulators regarding voltage management

Jurisdiction	Compliance Reports
ACT	link – Reports on investigations into pricing including FiT but nothing on voltage management
NSW	link – Few compliance reports from 2012 to 2019 available. Detailed information about network management including voltage.
NT	link and link – Power System Performance Review reports have some details about voltage management
Queensland	link – Few compliance reporting but nothing much on voltage management
SA	link and link – Few compliance reporting but nothing much on voltage management
Tasmania	link, link and link – Detailed information available about voltage compliance under performance reports and Network Reliability Review
Victoria	link – Distributor audit reports have general compliance information but not necessarily voltage management
WA	link and link – There are some methodology reporting under electricity access which has some details about low-voltage management (e.g. Western Power Network) https://www.erawa.com.au/cproot/21282/2/AA4-Access-Arrangement---Amended-for-Pricing-Corrections-clean-PDF---June-2020.PDF https://www.erawa.com.au/cproot/20193/2/ERA-Approved---Appendix-C.2---Distribution-Low-Voltage-Connection-Scheme.pdf