25 July 2022

Energy Security Board
Via email: info@esb.org.au

Response to Capacity Mechanism Project High-level Design Paper

Thank you for the opportunity to comment on the ESB's Capacity Mechanism Project High-level Design Paper (Paper).

Quinbrook Infrastructure Partners (www.quinbrook.com) is an infrastructure investor that invests in clean energy in the UK, the US and Australia. Our portfolio companies include:

- a NEM connected baseload renewable energy generator, Cape Byron Power (www.capebyronpower.com);
- an electricity retailer that prides itself on not gouging customers and who won the 2021 Finder Award for green energy retailer of the year in Australia and received a 4.5 Green Electricity Rating from Greenpeace, Energy Locals (www.energylocals.com.au);
- an community energy network business that prides itself on helping customers save costs by taking control of their energy needs, Energy Trade (www.energytrade.com.au);
- Lockyer Energy Management Pty Ltd (https://lockyerenergy.com.au/) which is developing a hybrid peaking and utility battery project in Queensland; and
- Supernode (https://supernode.com.au/) which is developing industrial scale data centre sites across Australia, including the flagship Brendale site (https://www.quinbrook.com/news-insights/quinbrook-launches-2-5-billion-supernode-data-storage-project-in-brisbane-to-be-powered-by-renewables-and-battery-storage/).

Our multiples channels of involvement in the NEM, across different levels of the industry, allows us to provide balanced "whole of industry" opinion and set of potential refinements to the NEM2025 design. Additionally, our portfolio companies in UK and US markets (which include utility wind, solar and batteries, distributed peaking generation and Flexitricity (www.flexitricity.com) a demand response and flexibility platform) give us an operating knowledge of alternative market designs. Both UK and US markets are currently experiencing comparable electricity market issues to Australia driven by high prices in global fuel markets, with policy makers also considering comparable reform programs in response to both immediate and longer-term market challenges.

Our response builds on our previous submissions[1] and is structured as a short paper.

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[1] Quinbrook Infrastructure Partners, *Response to P2025 Market Design Consultation Paper*, June 2021. See: https://web.archive.org.au/awa/20211005065856mp_/https://energyministers.gov.au/sites/prod.energycouncil/files

OVERVIEW

The NEM needs to rapidly decarbonise whilst ensuring minimum levels of reliability and security of supply. This requires unprecedented investment in bulk renewables (wind and solar PV) plus flexible supporting capacity (storage, industrial demand response and flexible generation). Quinbrook is broadly supportive of a well-designed capacity market to accelerate this investment whilst keeping the lights on and consumer bills manageable.

Capacity contracts should prioritise investment incentives by providing long-term revenue certainty, including inflation protection, that allows for rapid capital deployment into new capacity. The scheme should ensure appropriate risks are left with asset owners (availability risk) and that unmanageable risks are not introduced by the arrangements (revenue clawbacks unrelated to availability, retroactive re-pricing of existing capacity contracts). There needs to be consideration of hybrid sites (renewables plus storage, renewables plus demand response, etc) with regard to performance settings and derating.

We have three main concerns. First, the capacity mechanism if deployed as planned will not result in material new investment until 1 July 2027 or later, and could delay investment prior to the first auctions. The scheme should be designed to incentivise near-term investment. Additionally, there is a case for transitional mechanisms to complement the scheme and we make several suggestions. Second, the impact of changes to spot market prices (via changes to the Market Price Cap (MPC) and related reliability settings) risks reducing liquidity in Australia's wholesale contract markets and damaging participants ability to manage wholesale market risk. We suggest a settlement arrangement that would preserve scarcity pricing signals at today's MPC levels whilst limiting cost pressures on consumers. Third, we note the increasing breadth of AEMO's role in the NEM as system operator, market operator, transmission planner for Victoria and South Australia, Consumer Trustee for NSW, and, through the capacity market, generation system planner. Consolidation of roles in a single entity goes against best practice governance and trends in comparable markets (i.e. the UK's recent split of system operations from network owner/planner through the creation of the independent National Grid Electricity System Operator).

The energy market crisis of June 2022 only sharpens the requirement for practical reform that addresses the challenges facing the NEM and most importantly consumers, whether they be residential 'mums and dads' or

/publications/documents/71.%20Quinbrook%20Response%20to%20P2025%20Market%20Design%20Consultation%20Paper_0.docx
and
Quinbrook Infrastructure Partners, *Submission on P2025 Market Design Consultation Paper*, November 2020. See: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Quinbrook%20Response%20to%20P2025%20Market%20Design%20Consultation%20Paper%20.docx
and
Quinbrook Infrastructure Partners, *Submission on Coordination of Generation and Transmission Infrastructure Proposed Access Model*, November 2019. See: https://www.aemc.gov.au/sites/default/files/2019-11/Quinbrook%20Infrastructure%20Partners%20-%20recieved%209%20November%202019.pdf

industrial consumers of power. A well-designed capacity mechanism is a strong step in this direction and we welcome its implementation.

INCENTIVISING INVESTMENT

Quinbrook believes the benefits of a capacity market arise from derisking investment and thereby accelerating capital deployment into new capacity. This is best achieved by ensuring investors can depend on long-term revenue from the capacity contract. We suggest the following as critical design requirements:

- **Long term.** Contracts for new capacity should be long-term, ideally 15 years. This allows for significant amortisation of project capital costs versus capacity contract revenue, significantly derisking investment.
  Investment will be maximised where projects can be project financed, leveraging debt capital markets. Debt lending levels are a function of a project's firm revenues (such that debt coverage is achieved). Long tenor capacity market contacts maximise the ability of proponents to achieve efficient gearing levels for projects, enhancing the extent to which equity capital translates into constructed MWs of investment.
  We suggest that the tenor of capacity contracts should be 15 years for new capacity and 1 year for existing capacity. The ESB should consider grandfathering capacity built from now to the first auctions as 'new capacity' to avoid any stalling of investment while the scheme is finalised and implemented.
- **Revenue certainty.** The capacity payments should be fixed revenue payments with the only uncertainty on payback levels related to performance (which can be managed by assets owners) and not external drivers. Floating volumes and/or prices undermine investment certainty and defeat the purpose of the capacity contracts to incentivise investment.
- **Inflation.** The capacity contacts should be inflation linked to CPI with no capping. This removes a significant source of investment risk and will maximise the level of capacity being deployed. Consumers will still benefit from real reductions in the cost of capacity over time via changes in prices over sequential auctions. But once a contract is awarded, payments should be firm and escalated over time to enhance the investability of the scheme.
- **Hybrid sites.** Quinbrook strongly believes that the future of energy markets will involve hybrid sites comprising multiple technologies and/or mixes of generation/storage/demand response. This is certainly the case for most of our current projects, including Project Gemini (solar plus storage), Project Fortress (solar plus storage), Supernode (storage plus demand response), Lockyer Energy (generation plus storage), Schofield Gardens (solar plus storage plus demand response). In particular, the ability to co-locate solar and storage allows far more certainty that the site will be available in the early evening peak versus a stand-alone storage site that may be less likely to charge during a given day.
  De-rating, performance measurement and other scheme settings need to be tailored for hybrid sites or risk foregoing much of the flexibility such sites create through co-located assets.

- **Performance.** Quinbrook recommends a commercial focus on performance. The GB capacity market provides a practical and working model based on availability during actual events. Payment for availability when it is actually needed is important as time-based availability risks missing periods of actual need, undermining the scheme and reducing long-term revenue certainty (through risk of regulatory change). Quinbrook supports payments based on rolling average annual availability and availability during Low Operating Reserve (LOR) conditions (ESB Option 3). Payments should be overweighted to annual outcomes consistent with the nature of capacity availability and the need to incentivise investment, we suggest an 80/20 split between annual and event driven payments. Putting too high a weighting on event driven payments will lead investors to discount these revenues in whole or in part which has the potential to significantly reduce investment under the scheme.
- **Changes to MPC.** We discuss our views on the relationship between settings in the energy only market, particularly MPC, and the capacity market below. Our preferred position is that there should not be changes to MPC. If no change is an unacceptable approach then we suggest changes should be to settlement, not MPC itself. Specifically, MPC should be maintained and the capacity contacts should settle to provide a floor outcome relative to realised gross profit on a $/MW/annum basis. This approach retains the short-term benefits of sharp price signals, removes any risk of reductions in wholesale contract market liquidity and directly reduces the cost burden on consumers.

We provide more detailed feedback in the Responses to the ESB's Specific Questions section at the end of this paper.

AREAS OF CONCERN

We have three main concerns: 1) the speed with which capacity will be deployed; 2) the impact of changes to spot market prices and contract market liquidity; and 3) the increasing breadth of AEMO's role in the NEM. We discuss each of these points in turn.

Transitional measures are needed now

The capacity mechanism if deployed as planned will not result in material new investment until 1 July 2027 or later.[2] The NEM needs capacity now, as illustrated by the ongoing events of winter 2022. The capacity market design could incentivise near-term investment as follows.

First, the inaugural auctions in 2023 could host auctions for more delivery years. E.g. the 2023 auctions could be run for T-1, T-2, T-3 and T-4. Auctions in subsequent years could then progressively drop the intervening years to reach the intended steady state tenors. E.g. the 2024 auction runs T-1, T-2 and T-4 and the 2025 auction reaches the steady state of T-1 and T-4. This results in three 'extra' auctions being run for delivery over 2025 and 2026 as shown below (with the extra auctions in grey). This approach would increase the ability

[2] Assuming that only T-1 and T-4 auctions are held in 2023 for delivery on 1 July 2024 and 1 July 2027 respectively. Most scale projects would require at least 16 months lead time to secure a grid connection and equipment. This means scale projects would miss the initial T-1 auction but would be able to deliver prior to the T-4 delivery year.

of projects that achieve a ‘shovel ready’ status after 2023, but which could deliver over 2025/2026, to secure a capacity contract and achieve final investment decision.

Auction year \ Delivery year	2024	2025	2026	2027	2028	2029	2030
2023	T-1	T-2	T-3	T-4			
2024		T-1	T-2		T-4		
2025			T-1			T-4	
2026				T-1			T-4

Second, there is a risk that the capacity market itself creates an incentive to delay investment in new capacity prior to the market coming on foot. For example, projects that would otherwise receive final investment decision now and reach commissioning by 2024 or 2025 have an incentive to delay to the first capacity auctions in 2023 in order to achieve a long tenor capacity contract for new capacity as opposed to a short contract as existing capacity.

This can be avoided by grandfathering. Specifically, by allowing any capacity commissioned from the announcement of the capacity market (e.g. from 1 January 2022) to participate in the first 2023 auctions as ‘new capacity’ and to be eligible for long-term contracts.

Additionally, there are many actions that other, non-ESB, stakeholders could take to mitigate the current crisis and incentivise new investment in the NEM. For example:

- The current crisis is fundamentally related to the cost of fuel used to generate electricity – gas and coal. Both gas and coal markets are internationalised and are experiencing extreme price volatility due to the Ukraine crisis. Making more fuel available for domestic consumption would lower prices in input fuel markets and reduce pricing pressure in the NEM.
    - The federal government could enact the Australian Domestic Gas Security Mechanism (ADGSM)[3] to limit export of LNG from the east coast. Current rules allow the hard export cap under this mechanism to come into effect on 1 January 2023. Legislative change could allow this to be enacted sooner. AEMO’s 2022 Gas Statement of Opportunities (GSOO) forecast that LNG would make up nearly 75% of east coast, pre-crisis demand for gas.[4] High gas prices have most likely significantly reduced non-LNG, east coast gas demand. A 10% decrease in LNG export volumes translates into a 30% increase in supply to the pre-crisis domestic east coast market demand.

[3] See https://www.industry.gov.au/regulations-and-standards/securing-australian-domestic-gas-supply

[4] AEMO, *GSOO 2022*, March 2022, see https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2022/2022-gas-statement-of-opportunities.pdf?la=en

- The NSW energy minister sought temporary powers to similarly limit coal exports.[5] Such powers could also be used to free up coal supplies to domestic markets.

- In some cases, outcomes in fuel markets have been exacerbated by NEM market rules. The most obvious example is the inconsistency between administered price caps for gas and power markets. This meant that gas generators were guaranteed to run at a loss once both markets were price administered. Furthermore, the NEM administered price cap of $300/MWh has never been escalated (unlike MPC) and has the consequence of eliminating any hedge cover from $300/MWh cap contracts when the administered cap is enacted for an extended period (as there can be no difference payments to the retailer on a $300/MWh cap when the spot price is capped at that level).

  We believe it is important to harmonise administered prices across gas and electricity markets. Quinbrook broadly supports Alinta's rule change proposal to increase the NEM's administered price cap[6] and believes this should be fast tracked as part of avoiding further market suspensions over 2022.

- The other key issue arising from the NEM market rules is the recovery of generator compensation. AEMO recovers compensation arsing from directions via lump sum charges levied on retailers. These arrangements are tailored to small recovery amounts, not to system wide and systemic compensation levels. Retailers are currently highly financial stressed.
  - Four retailers (Pooled Energy, Weston Energy, Enova Energy and Apex Energy) have entered administration.
  - At least seven have advised customers to switch to another provider (Electricity in a box, ReAmped, LPE, Discover, Elysian, Future X and Glow Power)[7] with a number having also announced significant price increases.
  - A further 20 are only accepting customers on regulated standing offers (1st Energy (excluding Tas), Amber, Bright Spark Power, Brighte Energy, CovaU, Dodo (Qld and SA), GEE Energy, Mojo Power, Momentum Energy, Nectr, On by Energy Australia, Ovo Energy, People Energy, Powerclub, Powerdirect (part of AGL), QEnergy, Radian Energy, Smart Energy and Tango Energy (NSW and Qld).[8]

  Further retailer insolvencies may arise once compensation payments are levied, especially given that the Default Market Offer (DMO) in each region does not reflect the crisis. Amending the DMO would likely avoid retailer insolvencies and maintain some level of retail competition. Levying the compensation charges on a variablised basis would ensure passthrough to retail tariffs was clearer and more transparent.

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[5] See https://www.abc.net.au/news/2022-06-17/nsw-energy-temporary-emergency-coal-generator-powers-matt-kean/101160956

[6] We are less clear that $600/MWh is the right level and could see an argument for administer prices at a lower level but no lower than $400/MWh.

[7] See https://www.news.com.au/finance/business/other-industries/victorian-energy-provider-electricityinabox-begs-customers-to-leave/news-story/4ecdbd71064a27822b1427334898eb99

[8] See https://wattever.com.au/electricity-retailers-ditch-market-offers/

Alternatively, government could absorb the generator compensation payments on the basis of inflation mitigation and consumer protection. The RBA has increasingly referred to high energy costs as part of its rationale for raising interest rates. Limiting impacts to end consumes could mitigate some of this effect. Additionally, state governments are already offering one-off support payments to consumers, it may be more efficient to reduce the need for compensation at source.

- State and federal governments could bridge the period to the capacity market coming online by running *ad hoc* processes to support new capacity. The NSW Long-Term Energy Service Agreements (LTESAs)[9] could serve the role of such a transitional measure. There may be an argument for other NEM regions to pursue a similar strategy to support new investment to market prior to the capacity market coming on foot consistent with the approach taken by the South Australian government after the 2016 blackout.
- Customers are increasingly committing to hourly, zero carbon energy. Both Google[10] and Microsoft[11] have committed to meeting 100% of their power demand from zero carbon sources on an hourly level by 2030. The US Government has made commitments[12] ensuring net zero supply of 50% of US Government power purchases by 2030. We believe many industrial power users (data centres, telcos, green hydrogen and others) are currently making similar predictions. These customers are willing to pay a premium to underwrite not just bulk renewables, but also the storage or demand response assets needed to make them dispatchable around the clock. The progress made by these progressive market participants could be accelerated through changes to the Renewable Energy Target (RET).
  The RET could be amended to mandate an hourly minimum purchase of renewable energy. This would be a minimum change to a well understood and exiting set of arrangements that could be implemented rapidly. Such a change would incentivise new renewables, storage and demand response – exactly the capacity needed in the NEM. Hourly targets be set at low levels with a long term ramp up (e.g. 10% initially rising to 20% by 2040). We view such a scheme as a 'no regrets' policy change given the relative ease and speed of implementation relative to the impact on investment in new, green and dispatchable energy. We recognise that the ESB is already managing several major reform workstreams as part of the NEM2025 process, however we think this consumer led approach is worthy of further consideration.

Changes to the MPC risk wholesale contract market liquidity

Our key concern is that material reductions to MPC are introduced as part of capacity market reforms.

Reducing the MPC as a complement to introducing a capacity market risks reducing the efficiency of the NEM. The NEM's high MPC enhances the productive and allocative efficiency of the NEM via strong incentives to

[9] See https://www.energyco.nsw.gov.au/index.php/industry/longterm-energy-service-agreements
[10] Google, *24/7 by 2030: Realizing a Carbon-free Future*, September 2020.
[11] Microsoft, *Made to measure: Sustainability commitment progress and updates*, July 2021.
[12] Whitehouse press release, *President Biden Signs Executive Order Catalyzing America's Clean Energy Economy Through Federal Sustainability*, December 2021.

produce and consume efficiently on short timescales (right now and today) and to prudently manage risk (via hedging today, tomorrow, next quarter, etc). Robust liquidity in wholesale contract markets improves dynamic efficiency by sending longer term pricing signals via contract prices and by allowing all parties to have confidence that positions can be hedged and unwound at low cost.

Our preferred approach is to maintain MPC at current levels (i.e. no change due to the capacity market). A second-best approach is to change how the capacity contract settles such that it acts as a floor relative to wholesale market outcomes. We oppose introducing a capacity market and materially reducing the MPC.

Relative to the current energy-only market design, a capacity market should only increase the level of investment. If the energy-only design is delivering an optimal level of investment, then any capacity market should clear at zero prices (as parties are intending to invest anyway and bid zero into the capacity auction, especially if the auction is priced on a common clearing basis). If there is some degree of 'missing money' in the energy-only market, then the capacity auction should clear at a non-zero price and deliver extra capacity over and above the energy-only outcome. Other things equal, more capacity should reduce outturn spot prices.

It is critical to note that if the MPC is reduced then this will increase parties' offers in the capacity market, raising capacity prices.[13] So reducing MPC will, other things equal, reduce the cost of spot purchases faced by consumers but will also increase the cost of capacity payments. The key question is whether there is a net cost increase to consumers across both capacity and spot charges.

Arguably, there is no need to alter MPC settings in the presence of a capacity market as pricing in the two markets should be linked. Expectations of high wholesale price levels and volatility should lead to participants lowering their capacity market offers and to lower capacity prices. Expectations of low wholesale price levels and volatility should lead to participants raising their capacity market offers and to higher capacity prices. In both cases, consumers pay for the aggregate outcome. In practice, outcomes are more complicated due to the different time horizons related to the pricing decisions – with pricing of capacity offers spanning the long-term (i.e. 15 years) and pricing of energy in spot markets spanning the very short-term (specific 5-minute dispatch intervals and contracting decisions on 1- to 3-year time horizons).

To the extent that the ESB and other participants feel there is a need to reduce wholesale market costs to consumers once a capacity market is introduced, we suggest this should be done at settlement rather than via changes to the MPC.

The capacity market will clear at some price level in \$/MW/annum terms. As currently envisaged, capacity contract holders would receive a revenue stream from the contract that would be completely separate from other wholesale market revenues and costs.[14] Similarly, under the ESB's recommendation, retailers would

[13] Reducing MPC would also reduce estimates of Net-Cost of New Entry (Net-CONE) that may be used as a price cap in the capacity auction.

[14] Wholesale market revenues and costs include spot revenue, spot costs (e.g. for charging storage assets), ancillary market revenue, ancillary market cost allocation and contracting costs (difference payments, premiums and option fees).

face capacity charges (to fund payments to capacity contract holders) that are completely separate from other wholesale market revenues and costs. As such, end consumers would face the sum of costs across capacity and spot markets.

The alternative is to settle the capacity payment relative to overall profit outcomes for the capacity such that the capacity payment sets a profitability floor. For example, if capacity holds a capacity contract priced at $10/MW/annum then settlement is relative to Gross Profit defined as:

Gross Profit = *Capacity Payment + Wholesale Payments*

where

Wholesale Payments = *Net Spot Revenue (net of any charging costs for storage)*

+ Net Ancillary Revenue (net of any ancillary cost allocation)

+ Net Contract Revenue (net of any outgoing contract payments)

Settlement would then be a top up:

- If Wholesale Payments are greater than or equal to the capacity contract price, then the Capacity Payment = zero.
- If Wholesale Payments is les than the capacity contract price, then the Capacity Payment = capacity price - Wholesale Payment. E.g. if the Wholesale Payment is $8/MW/annum then the Capacity Payment would be $2/MW/annum, truing the contract holder up to the capacity price of $10/MW/annum.

The benefits of this approach are that it directly mitigates any total cost impact on consumers without a need to change the MPC and incur related weakening of price signals, market efficiency and contract market liquidity. Potentially the largest benefit is the incentive this creates for the entity administering the capacity market (AEMO) to ensure efficient procurement. Under the above model, capacity payments would only be made at times when wholesale market prices were low relative to cleared capacity prices – this likely correlates with times during which there has been over-procurement of capacity and provides a built-in check on the market administrator.

The treatment of contract payments within the definition of Gross Profit could involve administrative burden. However, we think including contract payments is necessary in order to avoid parties capturing windfall gains through contracting. E.g. if capacity prices and forward contract prices are high in year 1 for year 2, and outturn spot prices in year 2 are low, and a contract holder sold forward contracts for year 2 at the high year 1 prices *then* the contract holder could be made up under a Capacity Payment whilst also having realised revenues under the sold forward contract position.

Settlement of capacity contracts in this manner would be a departure from comparable international capacity markets and would impact how participants offered into the market. We feel the benefits of both avoiding downsides associated with a reduced MPC and limiting cost impacts on consumers make this approach worthy of consideration to the extent that it avoids material reductions in MPC.

Let's not forget good governance

We note the increasing breadth of AEMO's role in the NEM. AEMO currently fulfills the following roles:

- NEM system operator
- NEM market operator
- NEM transmission planner for Victoria and South Australia
- Consumer Trustee for NSW
- System and market operator for Australia's east-coast gas markets.

The capacity market would add a further role of *de facto* generation system planner.

Our comments are not to disparage AEMO's performance but rather to point out the increasing concentration of roles in a single entity in the NEM. In our view, this is contrary to best practice governance of energy markets. For example, the NEM explicitly separates rule maker (the AEMC) from rule enforcer (the AER). This is to provide a check and balance. Similarly, the GB market recently established an independent system operator, National Grid Electricity System Operator (NatGrid ESO). This reform addressed concerns about having the transmission network owner and operator (National Grid) also acting in the role of system operator.

It is worth noting that AEMO, in its April 2022 update to the Electricity Statement of Opportunities[15] (ESOO), did not forecast any unserved energy outcomes in the NEM until 2024-25. That is AEMO did not forecast any upcoming reliability issues in the NEM in April 2022 and was caught by surprise (like most participants) by the events of May and June 2022. We feel it is critical that there is independent oversight of AEMO's role in any capacity market, particularly with regard to setting procurement levels, the assumed auction demand curve and capacity market price caps, how capacity is derated and how performance is measured.

An independent body should have ultimate responsibility for these key settings. A candidate entity is the Reliability Panel, the independent panel that is currently responsible for ensuring the NEM delivers reliable supply (via setting of MPC and other market settings). Making the Reliability Panel responsible for capacity market settings and wider reliability settings would mean outcomes were set holistically by a single entity with the support of all market bodies, including AEMO. AEMO would then be responsible for operational issues consistent with its system/market operations mandate.

WE WELCOME POSITIVE REFORM

Decarbonisation of the NEM is happening due to economic and social drivers. The market needs to protect consumers from unmanageable energy costs and ensure the reliability and security of supply as this decarbonisation is realised. The energy market crisis of June 2022 only sharpens the requirement for practical reform that addresses the challenges facing the NEM and most importantly consumers, whether they be

[15] AEMO, *Update to 2021 Electricity Statement of Opportunities*, April 2022, see: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/update-to-2021-electricity-statement-of-opportunities.pdf?la=en

residential ‘mums and dads’ or industrial consumers of power. A well-designed capacity mechanism is a strong step in this direction. We welcome its implementation and look forward to contributing to finalisation of the design.

Yours Sincerely,

Brian Restall
Senior Director
Quinbrook Infrastructure Partners

RESPONSES TO THE ESB'S SPECIFIC QUESTIONS

Below we respond to the ESB's specific questions in the consultation paper (Paper). We have only responded on questions where we have a specific comment, not on every question.

ESB Questions	QB Response
Question number	
Q2. Do you agree that the capacity mechanism should provide for multiple zones being the existing NEM regions?	Yes, noting the exact method by which the auction accounts for inter-regional linkages is a complex question. The simplest approach is to account for inter-regional linkages via the *ex ante* approach used to determine the Target Capacity, which will inherently assume some level of interconnector flows as discussed (Paper, page 36). It is less clear if or how a party could bid capacity into the regional auction where the plant was located *and* into an adjacent region auction (where the bid would be coupled to some form of capacity right to transfer power across the regions). Would the auction want to allow for this (through co-optimisation or iterative cycling across the regional auctions) or would proponents be forced to pick a preferred region and only participate in a single auction? This also raises questions about how the auctions could incorporate changes to the zonal structure of the NEM, either a change in the existing regional boundary structure (of which there is precedent) or a move to nodal pricing. PJM's zonal capacity auctions overlay their nodal market and this appears the simplest approach (i.e. keep the NEM regions) but does raise the question on how the auctions will adapt to changes in the underlying transmission system over time. It is easy to imagine a world where the REZ's change flow outcomes to the point that there is a clear argument for running a separate auction for the REZ (which would likely deliver a lower price) versus the region receiving the bulk of REZ exports (which would likely deliver a higher price). Part of PJM's zonal capacity market structure was in response to concerns regarding the geographic distribution of capacity market outcomes.

Q3. Is there sufficient evidence to say that the at-risk periods can be defined on a time-based definition?	As highlighted by the ESB, the data suggests that a static, time-based definition is not possible. For example, summer peak times have shifted significantly from mid-afternoons to evening with the rise of solar PV. Shifts in the timing of peak system usage are likely to occur as more variable renewables and storage are built. A time based definition of 'at risk' periods will certainly be wrong and risks reducing the perceived effectiveness of the capacity market (via a perception that capacity is being paid to show up at the wrong time). Ultimately, this leaves a degree of regulatory risk on participants (as future changes to the capacity market are less predictable than well considered initial design).
Q4. If there is a risk of the emergence of more than one at-risk period in the NEM how should that be addressed?	Yes. An event driven approach that seeks to forecast a distribution of outcomes for the purpose of derating is a first best approach.
Q5. The de-rating factors produced by different at-risk period definitions and modelling methodologies can show large ranges particularly for non-traditional technologies. How should this and potential year to year variability in de-rating factors be addressed?	It is critical that de-rating factors remain constant over a given capacity contract to ensure investor certainty. Within this constraint, there is more scope to update de-rating factors between auctions to account for the best information (i.e. prior to a party accepting a capacity contract). One approach is to allow participants to propose a binding de-rating level as part of their offer. Penalties for non-delivery would then incentivise participants to only offer what they believe can be delivered. This would remove the reliance on complex modelling.
Q6. What approaches should be used to de-rate different technologies? Should different approaches apply to different technologies?	If modelling is used, then ideally the same modelling approach should be used to determine derating of all capacity. A modelling approach is difficult to apply to storage and demand response given that participants would operate the assets to ensure maximal availability during critical events, whereas the capacity market administrator would be inclined towards conservative assumptions. This could systematically disadvantage the flexible capacity that is needed – storage and demand response. As noted in Q5, one approach is to allow participants to propose a binding de-rating level as part of their offer. Penalties for non-delivery would then incentivise participants to only offer what they believe can be delivered. This would remove the reliance on complex modelling.
Q7. What is the right balance between transparency/simplicity and accuracy?	Accuracy is important, but should be secondary to transparency/simplicity as this will maximise certainty and investment.

Q8. Should de-rating factors be determined at a technology class/region level or at a station level?	De-rating should be determined at the station/facility level. This is critical to ensure hybrid sites (combinations of generation/storage/demand response) are fairly treated under the capacity market and that the benefits of co-location can be fully recognised. E.g. co-locating solar and storage makes it more likely that the storage will be charged during the evening peak relative to a stand-alone storage system.
Q9. Do you agree with the approach to setting the forecast capacity requirement and the target capacity in a region?	Broadly agree.
Q10. How should the target capacity be determined where there are gaps in more than one region?	Via joint modelling. Having AEMO conduct modelling but ultimate responsibility for the target capacity settings rest with an independent party (e.g. the Reliability Panel) is consistent with good governance.
Q11. Should retailers have a role in a centralised capacity mechanism?	Given AEMO will set the overall target, there seems little benefit in having retailers participate as bidders. Retailers should be able to offer capacity (demand response, behind the meter generation, etc) on behalf of customers.
Q13. Do you agree with holding two auctions for each delivery year and is this timing appropriate? If no, what auction frequency and timing is appropriate and why?	Yes. We support a T-1 and T-4 steady state approach to annual auctions. We also suggest that the initial auction should include 'extra' auctions to cover the gap years and ensure rapid investment. E.g. the 2023 auctions could be run for T-1, T-2, T-3 and T-4. Auctions in subsequent years could then progressively drop the intervening years to reach the intended steady state tenors. E.g. the 2024 auction runs T-1, T-2 and T-4 and the 2025 auction reaches the steady state of T-1 and T-4. We also note that capacity commissioned after 1 January 2022 should be treated as 'new capacity' (eligible for long-term contracts) in the initial auction s held in 2023. This will mitigate any incentive to delay investment to secure a long-term capacity contract.
Q14. How should the timing of the auctions align with the notice of closure obligation?	The notice of closure should be aligned with the T-4 auction.

Q15. What are your views on how existing and new capacity should be treated in the auction process?	Existing capacity should participate mandatorily, should only be eligible for 1-year contracts, should be offer-capped at a low level consistent with reasonable estimates of fixed operating and maintenance costs (including a buffer to manage forecast risk) and should settle on the common clearing price of the capacity auction
Q16. Are there other considerations the ESB should take into account for the detailed design?	We suggest MPC should be maintained (not reduced) as discussed in the paper. To the extent that the ESB is concerned about cost pressure on consumers, we suggest that MPC should be maintained and the capacity contacts should settle to provide a floor outcome relative to realised gross profit on a $/MW/annum basis. This approach retains the short-term benefits of sharp price signals, removes any risk of reductions in wholesale contract market liquidity and directly reduces the cost burden on consumers. This is discussed in detail in our paper.
Q17. Do stakeholders have a view on the optimal duration of certificates or price certainty for new capacity?	Contracts for new capacity should be long-term, ideally 15 years. This allows for significant amortisation of project capital costs versus capacity contract revenue, significantly derisking investment. Investment will be maximised where projects can be project financed, leveraging debt capital markets. Debt lending levels are a function of a project's firm revenues (such that debt coverage is achieved). Long tenor capacity market contacts maximise the ability of proponents to achieve efficient gearing levels for projects, enhancing the extent to which equity capital translates into constructed MWs of investment. We suggest that the tenor of capacity contracts should be 15 years for new capacity and 1 year for existing capacity. The ESB should consider grandfathering capacity built from now to the first auctions as 'new capacity' to avoid any stalling of investment while the scheme is finalised and implemented.

Q18. Do stakeholders have a preference as to whether the investment support scheme provides guarantees of price only, or of both price and quantity?	The capacity payments should be fixed revenue payments with the only uncertainty on payback levels related to performance (which can be managed by assets owners) and not external drivers. Floating volumes and/or prices undermine investment certainty and defeat the purpose of the capacity contracts to incentivise investment. The capacity contacts should be inflation linked to CPI with no capping. This removes a significant source of investment risk and will maximise the level of capacity being deployed. Consumers will still benefit from real reductions in the cost of capacity over time via changes in prices over sequential auctions. But once a contract is awarded, payments should be firm and escalated over time to enhance the investability of the scheme.
Q19. Internationally, capacity mechanisms rely on some multiple of the net-cost of new entry (net-CONE) assessment to determine the capacity mechanism market price cap. Is this appropriate or should an alternative approach be used?	If existing generators are offer capped at estimates of fixed operating and maintenance costs then there may not be a need to offer cap new entrants (who are unlikely to have market power) and an arbitrarily high capacity market price cap could be used. To the extent that lower capacity market price capping is needed, then Net-CONE provides a commonly accepted approach, however it does introduce a strong dependency on forward modelling of wholesale market outcomes. It is important that the multiple used leaves enough head room for efficient investment accounting for forecast error in Net-CONE estimates.

Q20. How should the price settings interact with the energy market price? Over time, when settings are regularly reviewed, should the price settings in the capacity auction and the energy market be jointly determined?	We note the increasing breadth of AEMO's role in the NEM. AEMO currently fulfills the following roles: • NEM system operator • NEM market operator • NEM transmission planner for Victoria and South Australia • Consumer Trustee for NSW • System and market operator for Australia's east-coast gas markets. The capacity market would add a further role of de facto generation system planner. Our comments are not to disparage AEMO's performance but rather to point out the increasing concentration of roles in a single entity in the NEM. In our view, this is contrary to best practice governance of energy markets. For example, the NEM explicitly separates rule maker (the AEMC) from rule enforcer (the AER). This is to provide a check and balance. Similarly, the GB market recently established an independent system operator, National Grid Electricity System Operator (NatGrid ESO). This reform addressed concerns about having the transmission network owner and operator (National Grid) also acting in the role of system operator. It is worth noting that AEMO, in its April 2022 update to the Electricity Statement of Opportunities (ESOO), did not forecast any unserved energy outcomes in the NEM until 2024-25. That is AEMO did not forecast any upcoming reliability issues in the NEM in April 2022 and was caught by surprise (like most participants) by the events of May and June 2022. We feel it is critical that there is independent oversight of AEMO's role in any capacity market, particularly with regard to setting procurement levels, the assumed auction demand curve and capacity market price caps, how capacity is derated and how performance is measured. An independent body should have ultimate responsibility for these key settings. A candidate entity is the Reliability Panel, the independent panel that is currently responsible for ensuring the NEM delivers reliable supply (via setting of MPC and other market settings). Making the Reliability Panel responsible for capacity market settings and wider reliability settings would mean outcomes were set holistically by a single entity with the support of all market bodies,

	including AEMO. AEMO would then be responsible for operational issues consistent with its system/market operations mandate.
Q22. While the RRO requires mandatory participation for the largest three participants in a region, the ESB considers a methodology for determining market power should be applied to account for changing market concentration over time. Are there specific market concentration thresholds of concern?	Participation of existing capacity should be mandatory and existing offers should be capped at some estimate of fixed and operating maintenance costs.
Q23. Should market power mitigation measures be applied to capacity providers with large market shares in supply-side regardless of their market share in retail?	Yes, as per our response to Q22.
Q24. Do stakeholders support the proposal to integrate capacity mechanism settlement with the existing NEM settlement process? If not, what alternative process would better meet the design objectives?	Yes. There should be prudential offsetting between capacity and energy markets where possible.
Compliance Q1. Do you have preliminary views on compliance obligations for capacity providers?	We agree with performance risk sitting with asset owners. Compliance obligations should be commercially focused to ensure strong incentives to invest.
Compliance Q2. Do you have views on compliance obligations for new entrant capacity in advance of the delivery year?	Some form of escalating checklist against the T-4 auction is appropriate to ensure timely delivery of capacity. The checklist should include final investment decision, notice to proceed, binding grid connection, binding equipment procurement as steps prior to energisation.

Compliance Q3. Do you support the ESB's proposed performance model for consultation? If no, what other proposed model would be better and why?	Yes. We suggest an 80/20 split between annual and event driven payments.
Q25. Are there any issues with using LOR2 and LOR3 as the trigger for capacity payments? If yes, please explain the issues and any alternative triggers.	No. This leverages a well understood existing market concept.
Q26. How would an appropriate methodology year-round availability be determined?	Some form of rolling average availability. We suggest meeting 75% of the contracting availability level on a 12 month rolling average basis.
Q27. Do you support the ESB considering capacity payments based on availability throughout the year and during periods of system stress?	Yes.
Q28. If you support payments based on two factors, what is the preferred distribution of the first and second payment? Should more or less weight be given to responding to events?	We suggest an 80/20 split between annual and event driven payments.
Q29. To support revenue smoothing, should the ESB consider grouping events within the delivery year? If yes, what frequency (such as quarterly or monthly) is appropriate?	Payments should be smoothed if possible. Quarterly payments would assist in maintaining project cashflows (and mitigate lumpy retailer liabilities).

Q30. Should an upper threshold of performance events in a delivery year be considered? If yes, what is an appropriate threshold?	The key factor here would be to ensure storage was not disadvantaged if an extended market outage limited the ability to charge, leading to unavailability across a long and continuous market event. This occurred with storage assets (including ours) during the ERCOT 'big freeze' in 2021. An appropriate upper threshold in continuous availability would mitigate this risk.
Q33. Are there any other implications the ESB should consider in detailed design?	We suggest MPC should be maintained (not reduced) as discussed in the paper. To the extent that the ESB is concerned about cost pressure on consumers, we suggest that MPC should be maintained and the capacity contacts should settle to provide a floor outcome relative to realised gross profit on a $/MW/annum basis. This approach retains the short-term benefits of sharp price signals, removes any risk of reductions in wholesale contract market liquidity and directly reduces the cost burden on consumers. This is discussed in detail in our paper.
Q34. What is the appropriate combination of performance obligation and capacity de-rating methodologies?	Having a participant proposal model for de-rating (coupled with appropriate non-compliance penalties) should ensure alignment with performance. Under a modelled approach, modelling should attempt to match de-rating to performance as best as possible but there will always be mismatches.
Q35. Should de-rating be based on pre-defined time periods or a forecast of when the anticipated trigger periods are expected to occur?	We suggest event driven performance measurement is important for the perceived effectiveness of the scheme and ideally de-rating is also based on event driven outcomes.
Q36. Given VRE is likely to be particularly affected by any mismatch in the forecast and actual conditions during performance events, should special consideration be given to VRE's compliance with the performance obligation?	Ideally the same framework is used for VRE and other technologies, however VRE is likely to 'set the standard' given it is the hardest technology to assess. A participant proposal model could solve this by putting the assessment burden (and risk of mis-forecasting) on participants. It is important that compliance is measured on a station/facility level. This creates incentives for participants to co-locate VRE with storage and/or demand response to better manage performance during capacity market events.

Q37. Do you think the MPC should be reduced if a capacity mechanism is introduced, and if so, by how much? What key issues should the ESB take into account when considering this issue?	No. Reducing the MPC as a complement to introducing a capacity market risks reducing the efficiency of the NEM. The NEM's high MPC enhances the productive and allocative efficiency of the NEM via strong incentives to produce and consume efficiently on short timescales (right now and today) and to prudently manage risk (via hedging today, tomorrow, next quarter, etc). Robust liquidity in wholesale contract markets improves dynamic efficiency by sending longer term pricing signals via contract prices and by allowing all parties to have confidence that positions can be hedged and unwound at low cost. Our preferred approach is to maintain MPC at current levels (i.e. no change due to the capacity market). A second-best approach is to change how the capacity contract settles such that it acts as a floor relative to wholesale market outcomes. We oppose introducing a capacity market and materially reducing the MPC. Relative to the current energy-only market design, a capacity market should only increase the level of investment. If the energy-only design is delivering an optimal level of investment, then any capacity market should clear at zero prices (as parties are intending to invest anyway and bid zero into the capacity auction, especially if the auction is priced on a common clearing basis). If there is some degree of 'missing money' in the energy-only market, then the capacity auction should clear at a non-zero price and deliver extra capacity over and above the energy-only outcome. Other things equal, more capacity should reduce outturn spot prices. It is critical to note that if the MPC is reduced then this will increase parties' offers in the capacity market, raising capacity prices. So reducing MPC will, other things equal, reduce the cost of spot purchases faced by consumers but will also increase the cost of capacity payments. The key question is whether there is a net cost increase to consumers across both capacity and spot charges. Arguably, there is no need to alter MPC settings in the presence of a capacity market as pricing in the two markets should be linked. Expectations of high wholesale price levels and volatility should lead to participants lowering their capacity market offers and to lower capacity prices. Expectations of low wholesale price levels and volatility should lead to participants raising their capacity market offers and to higher capacity prices. In both cases, consumers pay for the

	aggregate outcome. In practice, outcomes are more complicated due to the different time horizons related to the pricing decisions – with pricing of capacity offers spanning the long-term (i.e. 15 years) and pricing of energy in spot markets spanning the very short-term (specific 5-minute dispatch intervals and contracting decisions on 1- to 3-year time horizons). To the extent that the ESB and other participants feel there is a need to reduce wholesale market costs to consumers once a capacity market is introduced, we suggest this should be done at settlement rather than via changes to the MPC. The capacity market will clear at some price level in $/MW/annum terms. As currently envisaged, capacity contract holders would receive a revenue stream from the contract that would be completely separate from other wholesale market revenues and costs. Similarly, under the ESB's recommendation, retailers would face capacity charges (to fund payments to capacity contract holders) that are completely separate from other wholesale market revenues and costs. As such, end consumers would face the sum of costs across capacity and spot markets. The alternative is to settle the capacity payment relative to overall profit outcomes for the capacity such that the capacity payment sets a profitability floor. For example, if capacity holds a capacity contract priced at $10/MW/annum then settlement is relative to Gross Profit defined as: Gross Profit = Capacity Payment + Wholesale Payments where Wholesale Payments = Net Spot Revenue (net of any charging costs for storage) + Net Ancillary Revenue (net of any ancillary cost allocation) + Net Contract Revenue (net of any outgoing contract payments) Settlement would then be a top up: • If Wholesale Payments are greater than or equal to the capacity contract price, then the Capacity Payment = zero. • If Wholesale Payments is les than the capacity contract price, then the Capacity Payment = capacity price - Wholesale Payment. E.g. if the Wholesale Payment is

	$8/MW/annum then the Capacity Payment would be $2/MW/annum, truing the contract holder up to the capacity price of $10/MW/annum. The benefits of this approach are that it directly mitigates any total cost impact on consumers without a need to change the MPC and incur related weakening of price signals, market efficiency and contract market liquidity. Potentially the largest benefit is the incentive this creates for the entity administering the capacity market (AEMO) to ensure efficient procurement. Under the above model, capacity payments would only be made at times when wholesale market prices were low relative to cleared capacity prices – this likely correlates with times during which there has been over-procurement of capacity and provides a built-in check on the market administrator. The treatment of contract payments within the definition of Gross Profit could involve administrative burden. However, we think including contract payments is necessary in order to avoid parties capturing windfall gains through contracting. E.g. if capacity prices and forward contract prices are high in year 1 for year 2, and outturn spot prices in year 2 are low, and a contract holder sold forward contracts for year 2 at the high year 1 prices then the contract holder could be made up under a Capacity Payment whilst also having realised revenues under the sold forward contract position. Settlement of capacity contracts in this manner would be a departure from comparable international capacity markets and would impact how participants offered into the market. We feel the benefits of both avoiding downsides associated with a reduced MPC and limiting cost impacts on consumers make this approach worthy of consideration to the extent that it avoids material reductions in MPC.
Q38. Do you agree that costs should be passed on via retailers, rather than NSPs?	Yes. This also allows for setoff of prudential requirements across capacity and energy markets where possible.
Q39. What do you consider to be the most appropriate mechanism to allocate costs to retailers?	Allocating cost on a demand basis (as opposed to usage) will ensure greater economic efficiency. Contribution to demand should be aligned with stress events where capacity contracts are called (e.g. LOR events), rather than network of system demand peaks (which may occur at times of high supply).

Q40. Do you think that Option 1 or Option 2 better meets the assessment criteria?	Option 1 better meets the criteria (is least worst).