Institute for Energy Economics and Financial Analysis
IEEFA.org

25 July 2022

Ms Anna Collyer
Chair, Energy Security Board
Submitted by email to: info@esb.org.au

RE: Energy Security Board Capacity Mechanism High-level Design Consultation Paper

Dear Ms Collyer,

Thank you for accepting IEEFA's submission to the Energy Security Board Capacity Mechanism High-level Design Consultation Paper, released in June 2022.[1]

The NEM is in the midst of decarbonisation and is likely to see 60% of coal capacity withdrawn by 2030 according to AEMO's ISP Step Change Scenario.[2] Replacement energy resources will be required in advance of the coal exits, but substantial uncertainty exists around the exact timing of the coal exits.

IEEFA recommends addressing the coal exit uncertainty challenge with one mechanism, and supporting new entrant investment with a separate mechanism if required, to ensure the mechanisms are targeted, effective and keep costs low. Reserve services augmentation could also be explored if deemed necessary.

Various options should be explored to:

- Provide more certainty and order around coal exits – options include a "reliability bond" and opt-in managed phase down agreements (in the absence of a comprehensive, enforceable, certain coal exit schedule);

- Ensure adequate levels of entry of new, low-emissions capacity – options include a storage target and government underwriting; and

- Augment reserve services – options include a capacity reserve, operating reserve and jurisdictional strategic reserve.

The capacity mechanism proposed by the ESB includes payments to all forms of generation capacity. However, this will not solve the current challenges facing the National Energy Market – as it will not provide certainty around coal exits and may lock in a high-emissions system for longer, discouraging new entrants. It is ill-suited

[1] Energy Security Board. Capacity Mechanism High-level Design Paper. June 2022.
[2] AEMO. 2022 Integrated System Plan. June 2022.

in valuing flexibility and low-emissions resources and is also likely to add to consumer costs, at a time when electricity prices are high.

Our report, There's a Better Way To Manage Coal Closures Than Paying To Delay Them[3], explores why the ESB's indicative proposal for a capacity payment (for which all generators would be eligible, including existing coal generators) will not effectively address the current challenges facing the NEM. This report also provides a suite of alternative policy options that would do a better job of ensuring new capacity enters in advance of the exit of older fossil fuel power plants, to maintain reliable supply while containing costs to consumers.

Energy Ministers and the ESB need to more thoroughly examine these options as well as proposals from other stakeholders instead of its preferred capacity mechanism in order to manage the exit of coal generators and entry of new low-emissions capacity. Many other proposals could more effectively direct the NEM towards a goal of 82% renewables by 2030.

If any kind of mechanism to support investment in capacity does go ahead, support should be provided only to capacity that is:

- Low emissions and compatible with rapid decarbonisation
- A new entrant
- Any dispatchable capacity should be flexible (e.g., resources with fast response times and ideally capable of charging-up on power not just discharging power)

Further detail on IEEFA's perspective on the capacity mechanism and other options is provided in the following response.

Sincerely,

IEEFA Australia Electricity Team

[3] IEEFA. There's a Better Way To Manage Coal Closures Than Paying To Delay Them. September 2021.

The challenge and opportunity at hand

The proportion of renewable energy generation in the National Electricity Market (NEM) has been growing steadily, while wholesale electricity prices trended downward over the years 2017-2020. The growth of renewables, initially driven by the Renewable Energy Target, is now being further supported by increasing cost-competitiveness of solar and wind technology, the NSW Electricity Infrastructure Roadmap, and a preference by some consumers for low emission power supply.

The ongoing growth in renewables has been challenging the operational regime and profitability of coal-fired power plants. Coal-fired power plants are inflexible so struggle to ramp down significantly in the solar period, meaning they can be subject to low and even negative wholesale electricity prices in the middle of the day. The ongoing challenge to the profitability of coal-fired power plants in the NEM was outlined in Frank Calabria, CEO of Origin Energy's statement when announcing the Eraring exit "the reality is the economics of coal-fired power stations are being put under increasing, unsustainable pressure by cleaner and lower cost generation, including solar, wind and batteries".[4]

This year, pressing issues in the NEM have led to skyrocketing wholesale electricity prices.

High international coal and gas prices due to the Russian invasion of Ukraine, as well as coal-fired generator outages and disruption in NEM coal supply have upset the supply-demand balance and caused electricity prices to rise in 2022.

This has highlighted that an ongoing heavy reliance on aging fossil fuel generators is problematic not just for carbon emissions but also reliability and affordability of power. Yet while there is a general acceptance that many of these power plants will exit sooner than had been planned for just two years ago, there is still an incredible level of uncertainty around which plants might exit and when, beyond the plants of Liddell, Eraring and Yallourn.

The uncertainty in coal exit timeframes deters investment in replacement capacity, as financiers are unsure of the outlook for electricity sales for new energy resources. Given how large coal power plants tend to be, if they stick around longer than expected it can mean a huge difference in the amount of electricity sales and revenue a new plant might earn.

Exacerbating the risks associated with this uncertainty is the fact that permanent exit of generators is likely to be preceded by curtailment of maintenance expenditure. This could lead to increasing prevalence of unplanned outages which, because they occur suddenly and with little notice in plants that have large unit sizes, can then pose great risks to both electricity reliability and prices.

While some coal generators have brought forward their closure dates in recent years, providing plenty of advance notice that is supportive of timely investment in

[4] Origin Energy. Origin Proposes to Accelerate Exit from Coal-fired Generation. February 2022.

new capacity, it cannot be assumed that this steady and orderly exit will continue with other generators. Closure of Eraring and Yallourn, as well as very high gas prices could lead to an uptick in electricity prices that could improve the financial outlook for the remaining coal generators. Coal prices and coal fuel supply situations could also change, either worsening or improving the financial outlook for coal generators. Coal generator closure dates could change very little, be brought much further forward, or high maintenance or coal costs could push coal generators out of the system unexpectedly and abruptly. Coal supplies such a large portion of electricity that the outlook for coal heavily impacts on electricity price and volume outcomes of other generators.

So, investors will be reluctant to invest as long as large levels of uncertainty exist around when coal might exit. Yet at the same time it is essential replacement capacity is installed in advance of coal exits. As shown by the exit of Hazelwood, if replacement capacity is not induced in advance of when the exit occurs, electricity prices can rise significantly, and reliability can be threatened.

Replacement generation capacity and transmission can take multiple years to build, yet it is a challenge to invest in the face of coal exit uncertainty. To ensure replacement capacity is in operation before coal generators exit the system, there needs to be more certainty around the actual coal exit dates, so investors and developers in new capacity can build resources needed in advance of the exits.

The current 42-month notice of closure rule has flaws.[5] Furthermore, there is also the issue that a such plants are likely to suffer increasing prevalence of unplanned outages in the months or even years preceding an announcement to permanently close the plant.

Solutions

To deliver more certainty around coal exit dates a long-term coal closure schedule could be set using an auction scheme, with such models recommended by Professor Frank Jotzo[6] and Blueprint Institute.[7] However, government appetite for such a policy may be low.

An alternative to a comprehensive coal closure scheme, potentially more acceptable in the political context, is implementing a bond scheme to penalise unreliable coal generators, while offering the option for financially distressed generators to enter into managed phase-down agreements.

Operators of large, ageing power plants that pose a risk to reliability could be required to put up a financial surety or "reliability bond" covering the next 42 months of operation in advance. If they failed to meet availability requirements over a given season they would forfeit a portion of their bond and also inject new funds

[5] IEEFA. Fast Erosion of Coal Plant Profits in the National Electricity Market. February 2021.
[6] Frank Jotzo and Salim Mazouz, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[7] Blueprint Institute. Phasing Down Gracefully. December 2021.

to restore the bond to its original value. If they closed without giving 42 months notice they would forfeit their entire bond.

Coal-fired power plants that are struggling to meet the predefined reliability outcomes which had become financially distressed could opt-in to a managed phase-down agreement with the government. Under such agreements they would agree to close permanently once adequate replacement capacity had been built. Payments would be provided to the distressed generator on achievement of availability (but not generation) targets which would be based on ensuring cash flow neutrality such that the generator would not incur further financial losses up until their closure. They could be given their "reliability bond" back as an incentive to enter the scheme. The terms of the contract should be defined in advance and made transparent and public.

The replacement capacity build required is significant. It will likely be dominated by variable renewable energy (VRE), as wind and solar are the lowest cost new build electricity generation resource in Australia[8] and their operation does not emit greenhouse gases. Energy storage is also a major requirement of the future NEM.

Investment support may be required to incentivise new entrants. Targeted investment support options could be explored including an energy storage target (for example the Renewable Electricity Storage Target proposed by Victorian Energy Policy Centre (VEPC)[9]) and government underwriting of new low-emissions capacity.

Other options could also be explored to ensure appropriate reserve services are available during the transition from a fossil fuel based grid to one dominated by renewables. Associate Professors Tim Nelson and Joel Gilmore have suggested AEMO could build up a reserve of standby dispatchable capacity, in addition to the reserves it holds under the Reliability and Emergency Reserve Trader (RERT).[10] Other reserves suggestions including operating reserve and jurisdictional strategic reserves, previously posed by the ESB.

IEEFA Position on the Capacity Mechanism

The Energy Security Board has proposed a generalised payment to all capacity through a centralised auction process run by AEMO. The proposal would see payments going to both existing generators and new entrants.

However, the proposal in its current form will not solve the challenges facing the NEM as it will not deliver certainty on coal exits**.** A coal-inclusive capacity mechanism could keep ageing coal-fired generators in the system for longer while providing no certainty around their exit dates. This could deter new entrants as existing generators are paid so are likely to stay in system longer than otherwise,

[8] CSIRO. GenCost 2021-22. July 2022.
[9] Bruce Mountain, Peter Harris, Ted Woodley and Peter Sheehan, Victoria Energy Policy Centre. Electricity storage: the critical electricity policy challenge for our new Government. May 2022.
[10] Tim Nelson and Joel Gilmore, The Conversation. Why including coal in a new 'capacity mechanism' will make Australia's energy crisis worse. June 2021.

leading to underinvestment in new renewables and storage. This would leave the National Energy Market more exposed to future unplanned coal outages, worsening reliability.

The mechanism in its current form is ill-suited in valuing flexibility. With increased levels of wind and solar in the NEM, and the falling cost of batteries, it is more important than ever that price signals faced by power generators are highly flexible to reflect changes in the supply-demand balance over short time periods. This is the very reason that regulatory authorities and Energy Ministers accepted the need to move to paying generators based on prices over five-minute intervals instead of 30 minutes, which began last year. The ESB's proposed capacity payment reflects a move in the opposite direction, towards a central planner attempting to guess years in advance how much power supply will be needed, over what time periods.

It is also ill-suited in valuing low emissions resources. The current ESB proposal includes no emissions requirements for participating generators, while the UK and Poland capacity markets have emissions limits on qualifying capacity.[11] [12]

Further, even with emissions limits imposed on capacity, capacity markets can still favour high emissions resources. Research published in Nature Energy detailed the risk that capacity market structures may be ill-suited in financing low carbon resources, stating:

> *"Introduction of a capacity mechanism has an asymmetric effect on the risk profile of different generation technologies, tilting the resource mix towards those with lower fixed costs and higher operating costs. One implication of this result is that current market structures may be ill-suited to financing low-carbon resources, the most scalable of which have high fixed costs and near-zero operating costs. Development of new risk trading mechanisms to replace or complement current capacity obligations could lead to more efficient outcomes."*[13]

A 2021 analysis of Poland's energy system under an energy system that included a capacity market compared to energy only market (with the analysis taking into account that "coal-fired units cannot participate in the capacity auction from July 1, 2020") found that:

> *"The introduction of a capacity market delays the decarbonisation of the power system and has a negative impact on carbon neutrality. Even though coal-fired units are phased out, they are mainly replaced by natural gas."*[14]

[11] IEA. Emissions limit on the Capacity Market Regulations. October 2021.
[12] UK Government Department for Business, Energy & Industrial Strategy. Carbon Emissions Limits in the Capacity Market. July 2021.
[13] Jacob Mays, David P. Morton & Richard P. O'Neill. Asymmetric risk and fuel neutrality in electricity capacity markets. 28 October 2019.
[14] Aleksandra Komorowska. Can Decarbonisation and Capacity Market Go Together? The Case Study of Poland. 20 August 2021.

Further, the capacity mechanism proposed by the ESB could be expensive. The proposal includes payments to all capacity types, including both new and existing. This could cost up to $430 per household per year based on experience from Western Australia.[15]

Many stakeholders, including retailers, universities, generators, think tanks and others, have expressed concern about the proposed Physical Retailer Reliability Obligation and the capacity mechanism proposals.[16] Concerns include that the proposal could lead to unanticipated costs and risks, slow the transition to a low-emissions system, and increase uncertainty in the energy market (among others). These concerns must be explicitly addressed.

The capacity mechanism proposed by the ESB is not the only option for managing the challenges facing the NEM. Other options should be explored to increase certainty with regards to coal exits and incentivise replacement capacity in advance of exits (as laid out above).

If any kind of mechanism to support investment in capacity does go ahead, support should be provided only to capacity that is:

- Low emissions and compatible with rapid decarbonisation
- A new entrant
- Any dispatchable capacity should be flexible (e.g., resources with fast response times and ideally capable of charging-up on power not just discharging power)

IEEFA Previous Analysis on Capacity Mechanism Proposal

IEEFA has been following the capacity mechanism discussion and analysing various aspects of the proposal through the duration of the ESB Post 2025 Market Design work. Our analysis has come to the following conclusions (see footnotes for links to detailed reports):

1. **The proposed capacity market is not likely to solve the challenges facing the NEM.** Already identified by the ESB, the challenges revolve around: a) high levels of uncertainty around coal exits; b) myopic market contracting behaviour; c) early mover disadvantage in power technologies subject to cost deflation; and d) unpredictable government intervention. The proposed capacity mechanism does not solve these challenges. Instead, it has the potential to increase uncertainty around coal exit, may not increase the duration of contracting (especially if decentralised), does not combat first mover disadvantage, and

[15] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[16] IEEFA. ESB Submissions and Directions Paper Summary. January 2021.

does not address the underlying reasons for governments regularly intervening in the electricity market.[17]

2. **The ESB's capacity mechanism proposal has the potential to impose a substantial additional cost on electricity consumers.** Experience from Western Australia's (centralised) capacity market, when applied to the NEM, indicates annual payments from consumers to generators of $2.9 billion to $6.9 billion a year.[18]

3. **The ESB's capacity market benefit calculation does not provide a full picture of the costs and benefits of the capacity mechanism.** A more comprehensive cost benefit analysis is required.[19]

4. **There are many other more targeted options to deal with the challenges facing the NEM while reducing emissions.**[20]

IEEFA Response to ESB Consultation Questions

Q1 What measures could be put in place to improve AEMO's forecasting process and to access the best information from retailers and large customers on their likely demand?

AEMO could forecast high capacity requirements to err on the side of caution, leading to an over-procurement of capacity. This cost would be borne by consumers. The capacity market in Western Australia faced this issue – AEMO forecast high capacity requirements leading to an over-procurement of capacity, and therefore unnecessary cost. [21]

The PJM capacity market has also "consistently over-procured relative to the target reserve margin".[22] This cost is borne by consumers.

If a centralised capacity mechanism is progressed, it would be key to enable AEMO to forecast demand accurately to keep costs to consumers as low as possible. IEEFA does not have suggestions regarding the processes around how this should be run.

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[17] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.
[18] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[19] RenewEconomy. The dubious modelling behind the Energy Security Board's capacity market proposal. 8 September 2021.
[20] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.
[21] AEMC. Profiling the capacity market debate. Accessed 24 July 2022.
[22] NERA for the ESB. Capacity Mechanism Summary of International Case Studies. March 2022.

Q2 Do you agree that the capacity mechanism should provide for multiple zones being the existing NEM regions?

The approach of defining capacity on a regional basis appears logical as existing market processes including ESOO could be incorporated with the capacity mechanism.

Q3 Is there sufficient evidence to say that the at-risk periods can be defined on a time-based definition?

A general capacity market mechanism will not ensure that capacity is available in actual periods that pose risk to the system, because it will not be possible to accurately forecast (years in advance) what those time periods actually are.

The ESB has proposed two methods of defining the "at-risk" periods:

- discrete time periods of the year, e.g., summer evenings on workdays
- on the forecast occurrence of a defined event, e.g., if there is Unserved Energy (USE).

Both methods are based on forecasting future risks to the system, which is challenging and fraught. There are frequent unexpected changes in supply and demand that cannot be predicted – due to unexpected failures in the system, unexpected weather patterns etc.

For example, fossil fuel generators withdrew their availability, leading to AEMO suspending the market in June 2022. Demand-supply balance was very tight and the system was at risk. This would not have been forecast to be an "at-risk" period because it was not a summer evening on a workday, nor was it forecast year/s in advance to IEEFA's understanding. This demonstrates that de-rating and paying capacity based on these pre-defined "at-risk" periods will not adequately compensate generators for their actual availability in actual system risk periods.

Any "at-risk" period is best captured by the energy market in which price changes on a five-minute basis and accounts for all market dynamics – ramping, generator maintenance, weather conditions, transmission, reserves etc.

The energy market, rather than a capacity market, should be utilised to make sure energy is available in "at-risk" periods. If deemed necessary, existing energy market signals could be augmented to ensure energy is available when needed, for example by adding penalties for being short of energy or ancillary services at an administered cost of non-supply.[23] Reserves could also be augmented through options such as a capacity reserve[24], strategic reserve and operating reserve.

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[23] Greg Williams, AEMC. Profiling the capacity market debate. Accessed 18 January 2022.
[24] Tim Nelson and Joel Gilmore, The Conversation. Why including coal in a new 'capacity mechanism' will make Australia's energy crisis worse. June 2021.

Defining certain "at-risk" periods and then derating capacity based on this could deliver higher payments to certain resources over others.

We note that the ESB's report is focused on so-called wind and solar "droughts" in the section exploring "at-risk" periods. We would encourage similar attention be placed on the potential for gas and coal fuel supply "droughts", which caused havoc in the NEM over 2022. There is also the matter of real, literal droughts which, as occurred over 2007/08, can lead to supply adequacy problems from low hydropower water storages, and inadequate cooling water for coal power plants.

Gas supply issues in the NEM are not unprecedented. Historically there has been two major extended gas supply shortages in Australia. The first was the explosion at the Longford gas processing plant in Victoria in 1998, which resulted in severe gas shortages for two weeks. The second case was the explosion at the Varanus Island gas processing plant in Western Australia in 2008. Repairs took three months and there were major gas shortages for the state.

This omission of these real-world energy adequacy events from the ESB's report is especially odd given the ESB is yet to provide detailed evidence of the likely frequency and severity of wide geographic spread, extended duration, and co-incident shortages of wind and solar at times of high electricity demand. There is one isolated example of wind and solar "droughts" provided in the report but no comprehensive analysis completed to IEEFA's knowledge.

Q4 If there is a risk of the emergence of more than one at-risk period in the NEM how should that be addressed?

In June 2022 – which is not the "summer peak" period, and was not a forecast USE period[25], the NEM was thrust into chaos with generators withdrawing availability and AEMO suspending the market. The capacity mechanism would not have de-rated capacity based on this event as it was not in the summer peak and was not forecast year/s in advance.

The capacity mechanism is not the correct mechanism to reward capacity for being available in actual system risk periods. The energy only market is best placed to do so.

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?

De-rating based on availability in summer/winter peaks and forecast events is fraught and has the risk of overcompensating dispatchable generators and undercompensating variable renewables. It is important to recognise that with wind and solar one needs to consider the fact that it is not the availability of individual

[25] AEMO. 2021 Electricity Statement of Opportunities (ESOO). August 2021.

generators that matters but rather that of the entire group of generators due to the nature of weather diversity.

Q6 What approaches should be used to de-rate different technologies? Should different approaches apply to different technologies?

The energy market is best suited to manage any "de-rating" as it is in real-time and will capture all the energy market dynamics, rather than trying to approximate availability in "at-risk" periods years in advance and pay generators based on those approximations. There will be errors in determining the "at-risk" period, and errors in forecasting availability and therefore de-rating.

De-rating based on availability in historical periods is fraught as generator reliability can decline significantly over time, meaning that generators could be overcompensated in the scheme (e.g., their reliability next year may be significantly lower than it was five years ago).

De-rating based on availability in *forecast* events is fraught as it relies on forecasting "at risk" periods – the events of June 2022 show that significant system risk events can be random and often unforecastable.

There are many challenges with applying a de-rating factor that make it very challenging to accurately forecast if a given plant is available in a given "at-risk" period. These challenges do *not* arise in the energy-only market. The energy-only market is a better mechanism for compensating generators for being available in certain "at-risk" periods.

Designing the capacity mechanism de-rating based on availability in "at-risk periods", i.e., peak periods or forecast events, could de-rate VRE significantly and allow fossil fuel generators to claim a high level of payments.

With this in mind, if a capacity mechanism goes ahead, we could encourage that the design moves away from the blunt "peak MW" definition for capacity accreditation that will de-rate VRE (and potentially also storage) but allow fossil fuel generators to claim maximum payments.

De-rating needs to consider flexibility (e.g. ability to ramp up and down, response times) as this will determine the ability for plant to respond to unexpected events that create supply shortages outside of the defined "at risk" period.

Q7 What is the right balance between transparency/simplicity and accuracy?

For a mechanism that has the purpose of encourage investment in new capacity, transparency is essential to ensure investor confidence and enable payments to be factored into business cases early on. Accuracy with determining actual at-risk periods will undoubtedly be difficult to achieve in the current capacity mechanism design.

Q8 Should de-rating factors be determined at a technology class/region level or at a station level?

No comment.

Q9 Do you agree with the approach to setting the forecast capacity requirement and the target capacity in a region?

The approach to setting the target capacity requirement – asking AEMO to forecast the de-rated capacity of participating providers and reliability gap/surplus – may not necessarily reach an efficient level of capacity.

AEMO may tend to over-procure capacity to ensure reliability. This occurred in Western Australia.[26]

Further, as the capacity target this is meant to be set four years in advance, there will be scope for substantial error in the forecast, translating to over- or under-procurement of capacity.

Further, this model will not guarantee long-term (beyond four years) investor confidence. A model setting long-term targets for storage or dispatchable capacity (as the RET provided for renewables) would provide higher levels of investor confidence further into the future, and likely drive higher levels of confidence in longer-term transmission projects requiring substantially more than four years' advance planning.

Target Capacity = De-rated Capacity of *Participating* Existing Providers +/- Reliability Gap/surplus

Source: Energy Security Board[27]

Q10 How should the target capacity be determined where there are gaps in more than one region?

No comment.

Q11 Should retailers have a role in a centralised capacity mechanism?

This could add substantial complexity. Including a role for retailers in a centralised capacity mechanism could allow for the exercising of market power by gentailers who both operate generators and serve customers. Design of any mechanism should work to mitigate market power.

[26] AEMC. Profiling the capacity market debate. Accessed 24 July 2022.
[27] Energy Security Board. Capacity Mechanism High-level Design Paper. June 2022.

Q12 If you support retailer involvement in procurement, what are your views on how this could operate?

No comment on the specifics, though IEEFA encourages market power mitigation as a priority in thinking through this topic.

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?

The ESB has proposed to hold two auctions:

1. Three or four years in advance (T-3 or T-4)
2. One year in advance (T-1)

Holding a first auction procuring lower levels of capacity, and then a second to procure additional capacity if necessary, could reduce the likelihood of over-procurement.

Q14 How should the timing of the auctions align with the notice of closure obligation?

Coal-fired generators should not be included in the capacity mechanism as they are high-emissions. Adding a revenue stream for coal generators is likely to keep the coal-fired power plants in the system for longer, potentially discouraging new entrants and reducing certainty around exit dates, rather than achieving the ESB stated goals of "facilitating or complementing the orderly retirement of ageing thermal generation" and "facilitating the timely entry of new generation, storage and flexible resources".[28]

Coal exit should be managed separately in a different, more targeted mechanism that provides certainty around exit dates, so how the notice of closure lines up with capacity auctions is not of great importance. IEEFA has outlined potential mechanisms to provide more certainty around coal exit dates including a bond scheme, phase down agreements and auctions for closure (as recommended by Professor Frank Jotzo[29] and Blueprint Institute).[30]

The capacity mechanism is unlikely to provide certainty around closure dates of coal generators. The mechanism proposed does not include penalties if the capacity is not available in the delivery year. Payment in delivery year is proposed by the ESB to be based on availability through the year (yet to be determined how this is calculated) and availability in LOR2 and LOR3 events (per option 3 outlined in the paper). The ESB states "nonperformance will result in the loss of capacity revenue

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[28] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.
[29] Frank Jotzo and Salim Mazouz, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[30] Blueprint Institute. Phasing Down Gracefully. December 2021.

but not directly result in the subsequent risk of the AER pursuing civil penalties on this basis."[31]

Given this, if generators are unavailable at different points in the delivery year, they would receive reduced capacity payments. So they are not explicitly penalised for unavailability but rather their capacity payments are just reduced.

For example, if generators behaved unexpectedly and reduced their availability per the events of June 2022, in the ESB's model[32] it appears they would still receive a capacity payment for their availability through the rest of the year (depending on how year-round availability is determined) and for their availability in other LOR2 and LOR3 events. It is just that their capacity payment would be reduced from the full amount.

In another example, if a generator closed at the end of a delivery year providing only 2 months notice of closure (rather than the 42 months required), under the ESB's model[33] it appears they could still receive capacity payments for their availability through the first 10 months of the year (depending on how year-round availability is determined), and for their availability in LOR2 and LOR3 events that occurred in the first 10 months of the year. The generator would not face a penalty, but rather just a reduced payment.

So, the capacity mechanism appears insufficient in preventing unexpected early closure, and also appears insufficient in ensuring appropriate levels of reliability and availability preceding closure. Energy Ministers and the ESB should explore other options to deliver orderly coal exit including a bond scheme, managed phase down agreement or auctions for closure.

Q15 What are your views on how existing and new capacity should be treated in the auction process?

A review of Poland's capacity market since its inception found that it did not effectively deliver incentives for investments in new power generation units but rather tended to reward existing power plants.[34]

> *"The results prove that the primary beneficiaries of the capacity market in Poland have been the existing units (including the refurbishing ones) responsible for more than 80% of capacity obligation volumes contracted for 2021–2025. Moreover, during the implementation of the capacity market in Poland, the planned units that signed long-term capacity contracts with a total share of 12% of the whole market were already at the advanced phases of*

[31] Energy Security Board. Capacity Mechanism High-level Design Paper. June 2022.
[32] Under Option 3 which was taken forward by the ESB for consultation.
[33] Under Option 3 which was taken forward by the ESB for consultation.
[34] Przemysław Kaszynski, Aleksandra Komorowska, Krzysztof Zamasz , Grzegorz Kinelski and Jacek Kaminski. Capacity Market and (the Lack of) New Investments: Evidence from Poland. 23 November 2021.

> *construction, and the investment decisions were made long before the implementation of the capacity market mechanism."* [35]

The NEM should not follow Poland's example in this manner.

A key stated purpose of the capacity mechanism is to incentivise new entrants. To do this, existing generators do not need to be paid in the scheme, and should be excluded.

There is a significant risk that a capacity mechanism could favour fossil fuel-based generation over renewables. A study published in Nature Energy has shown that in general, capacity markets models favour resources with lower fixed costs and higher operating costs – therefore typically favouring coal and gas generators, and disadvantaging renewables and other low-emission energy resources. The study states:

> *"Introduction of a capacity mechanism has an asymmetric effect on the risk profile of different generation technologies, tilting the resource mix towards those with lower fixed costs and higher operating costs. One implication of this result is that current market structures may be ill-suited to financing low-carbon resources, the most scalable of which have high fixed costs and near-zero operating costs."*[36]

There are many other mechanisms that should be explored, including a REST and government underwriting, as they have the potential to be more targeted, efficient and effective in supporting low emissions new entrants than a capacity mechanism.

However, if a capacity mechanism is selected, new capacity will have to be treated carefully in the mechanism to ensure that it is incentivised appropriately, and that the appropriate form of capacity – i.e. low emissions to align with net zero – is brought online.

New capacity could be provided with long-term contracts for delivery, rather than contracts for delivery for one year. This would provide more certainty around their future revenue. If they had a capacity contract to deliver for a year at a reasonable price, and the following years year the capacity prices tanked, their viability could be at risk. For this reason, longer-term contracts could be more effective for new entrants. Price setting for these contracts will need to be thought through carefully, as if they are too expensive, consumers will be saddled with high costs in the long term.

If the ESB did design the mechanism to include payments to both new and existing generators (a position which IEEFA does not support), then new and existing generators should be treated differently in the mechanism. The ESB has recognised

[35] Przemysław Kaszynski, Aleksandra Komorowska, Krzysztof Zamasz , Grzegorz Kinelski and Jacek Kaminski. Capacity Market and (the Lack of) New Investments: Evidence from Poland. 23 November 2021.
[36] Jacob Mays, David P. Morton & Richard P. O'Neill. Asymmetric risk and fuel neutrality in electricity capacity markets. 28 October 2019.

in prior papers that investment in new plant faces a range of challenges that aren't as problematic for existing plant. This includes:

- The technologies likely to be favoured by new entrants are subject to purchase price deflation over time which encourages delay.

- They need a higher degree of certainty over future revenues because they need to be confident they can recover capital costs.

Consequently, a portion of capacity under the capacity mechanism should be reserved for new entrants and this should grow over time, while the portion of capacity sought from existing generators should shrink. In addition, the Energy Ministers' principle for the scheme to be consistent with their net zero emission targets could be addressed by requiring:

- that the blend of existing capacity supported under the mechanisms needed to adhere to a steadily reducing emissions intensity target linked to the ISP Step Change Scenario;

- Any new capacity would need to be low emissions.

Q16 Are there other considerations the ESB should take into account for the detailed design?

ESB should include payments only to low emission capacity in the mechanism. It is key to align any mechanism with the Federal Government goal of 82% renewables by 2030 and net zero by 2050 (as explored previously).

Q17 Do stakeholders have a view on the optimal duration of certificates or price certainty for new capacity?

New capacity could be incentivised through a range of mechanisms including a storage target, government underwriting, and by providing certainty around coal exits (as explored previously).

However if the ESB continues with the capacity mechanism proposal, it will be key to ensure a level of revenue certainty in the long term for new entrants.

New capacity could be provided with long-term contracts for delivery, rather than a year, as addressed in Question 15. This would provide more certainty around their future revenue. If they had a capacity contract that allowed them to deliver for 1 year at a reasonable price, and the following years year the capacity prices tanked, their viability could be at risk. For this reason longer term contracts could be more effective for new entrants.

IEEFA recommends that any capacity mechanism only includes new capacity. However, if both new and existing were both included, as suggested earlier, the price received by new entrant capacity should be set via a separate auction and target to that of existing capacity. This should act to reduce the total cost to consumers of the overall capacity mechanism.

Q18 Do stakeholders have a preference as to whether the investment support scheme provides guarantees of price only, or of both price and quantity?

A support scheme for new capacity will likely require guarantees of both price and quantity to bolster investment certainty.

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?

This appears to be appropriate for new entrants. It would not be appropriate for existing generators (IEEFA does not support inclusion of existing generators in any capacity mechanism).

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?

A detailed analysis will need to be completed to determine the best approach. However, given a five-minute interval energy market is far better than a capacity mechanism in signalling the broad array of factors that can influence supply scarcity relative to demand, a far greater weight should be placed on generators being remunerated through the energy market rather than the capacity market. Although ideally, we'd simply stick with an energy-only market design for the NEM.

Q21 Are there other considerations the ESB should take into account when determining demand curves in the detailed design?

A sloped demand curve theoretically could assist in procuring an efficient amount of new capacity.

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?

No comment.

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?

No comment.

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?

Integrating the proposed capacity mechanism with the existing NEM settlement process appears a reasonable approach – though we note market participants will be better placed to respond to this question.

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 comment.

Q26 How would an appropriate methodology year-round availability be determined?

This is a highly complex issue that it not well suited to attempts to define in advance. In the end an energy only market is the best tool for appropriately awarding generators for their actual availability in periods of system stress.

Q27 Do you support the ESB considering capacity payments based on availability throughout the year and during periods of system stress?

This is a highly complex issue that it not well suited to defining in advance. In the end an energy only market is the best tool for appropriately awarding generators for their actual availability in periods of system stress.

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?

This is a highly complex issue that it not well suited to defining in advance. In the end an energy only market is the best tool for appropriately awarding generators for their actual availability in periods of system stress.

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?

No comment.

Q30 Should an upper threshold of performance events in a delivery year be considered? If yes, what is an appropriate threshold?

No comment.

Q31 Are there any other interactions with the existing energy only market that the ESB should consider when designing the capacity mechanism performance obligation?

No comment.

Q32 Are there any other compliance issues the ESB should be mindful of in detailed design?

The ESB model does not penalise capacity for being unavailable in periods of system stress – it only would provide lower payments to capacity providers (per option 3 proposed). It will not guarantee that capacity is available in the time periods in which it is required most.

Q33 Are there any other implications the ESB should consider in detailed design?

Interaction between any capacity mechanism and other incentives to drive new capacity into the market (e.g., NSW Electricity Infrastructure Roadmap), should be assessed. Interaction between a capacity mechanism and other market reforms and the contracts market also should be assessed.

We would point out that an energy-only market design can automatically adjust to reflect changes in the supply-demand balance as a result of some of these other government initiatives far better than a capacity mechanism.

Q34 What is the appropriate combination of performance obligation and capacity de-rating methodologies?

The ESB proposal – to de-rate capacity based on availability in peak periods or in forecast events, and then to make payments based on year-round availability and availability in LOR2 and LOR3 events – has inherent inconsistencies.

System stress events cannot always be forecast, so de-rating will not always reflect availability in actual system stress events.

Further, de-rating based on availability in peak or in forecast events, and then providing payments based on availability year-round (method for calculating this not yet defined by the ESB) and LOR2 and LOR3 events, creates a situation where capacity is de-rated based on their availability at a certain time period, and then paid based on their availability in, potentially, a different time period. This appears unfair and inefficient.

The energy only market is best at determining the availability of capacity and compensating appropriately.

Q35 Should de-rating be based on pre-defined time periods or a forecast of when the anticipated trigger periods are expected to occur?

Both are fraught, and an energy only market is the best mechanism to reward generators' availability in periods of system stress.

A forecast of anticipated system stress events cannot include all unexpected events. However, an energy market automatically reflects the broad diversity of factors that influence the supply-demand balance.

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?

The problem with the entire proposition for a capacity market is it assumes the value of capacity can be readily pre-defined by a narrow set of circumstances. It fails to recognise that sometimes system stress events are a very product of the fact that fossil fuel generators are often sized as large discrete generating units and groups of units which when they suffer an unexpected outage can leave the market struggling to cover the shortfall. Wind and solar power plants avoid such instantaneous large loss of capacity problems due to weather diversity and the ability to forecast weather reasonably accurately in advance and the fact the generating units themselves are modular and in the case of solar a solid-state technology with higher levels of inherent technology reliability. Yet the ESB has shown no awareness of the need to recognise this difference in risk to reliability in its design of a capacity mechanism. An energy-only, five-minute interval market design on the other hand does cater for this wide array of issues. This is why the ESB should not alter the current NEM design.

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?

A key role of the Market Price Cap (MPC) is to incentivise investment in new generators if required. By setting the MPC at the right level, in extended periods of low supply of energy then the MPC will be more frequently hit, offering high rewards in the energy market and incentivising new entrants.

The reported purpose of the capacity market is shown below from the Capacity Mechanism Initiation Paper.[37] From below, the capacity mechanism is aiming to ensure investment to facilitate timely entry of new generation, storage and flexible resources.

[37] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.

> The ESB considers that the objective put forward by Ministers for this design process[2] can be further broken down into two limbs to capture the aim of a capacity mechanism:
>
> 1. Ensuring investment in an efficient mix of variable and firm capacity that meets reliability at the lowest cost by:
>   - facilitating the timely entry of new generation, storage and flexible resources
>   - facilitating or complementing the orderly retirement of ageing thermal generation
>   - complementing other market arrangements addressing resource adequacy.
> 2. Increasing government and community confidence that the market will deliver resource adequacy and thereby reducing the need for interventions over the longer term.

Source: Energy Security Board[38]

The MPC and the capacity mechanism have similar objectives. The MPC could be used itself to achieve the required level of investment. And, if further investment support is required, government underwriting, storage targets and other targeted mechanisms could be an effective way to support new entrants rather than a capacity mechanism.

Q38 Do you agree that costs should be passed on via retailers, rather than NSPs?

No comment.

Q39 What do you consider to be the most appropriate mechanism to allocate costs to retailers?

No comment.

Q40 Do you think that Option 1 or Option 2 better meets the assessment criteria?

The ESB has presented two options to address inter-regional transfers.

- Option 1 – Recognise inter-regional transfers in the capacity requirement
- Option 2 – Explicit procurement of inter-regional resources

Analysis of inter-regional transfers is best addressed by the energy only market. Any attempt to de-rate one region's capacity contribution in peak periods to another region's is going to be very difficult as it depends on interconnector flows and these are variable. Also, assessment of performance obligations (availability through the year and availability in LOR2 and LOR3 periods) will also be challenging as LOR2 and LOR3 are called on a state by state basis.

[38] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.

Q41 Are there any other factors that the ESB should consider when assessing the relative merits of the options?

No comment.

Q42 Are there other ways to ensure that procurement of interstate capacity resources does not exceed inter-regional transmission limits, in addition to the two approaches outlined above?

No comment.

Q43 Do you think that where a market interconnector exists between two regions, it should be the entity that is eligible to submit inter-regional capacity bids?

No comment.

Q44 Do you think that proposed new market interconnectors should be able to participate in the capacity mechanism?

No comment.