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IEEFA Response to Capacity Mechanism Project Initiation Paper

Thank you for accepting IEEFA's submission to the Energy Security Board (ESB) Capacity Mechanism Project initiation paper, released in December 2021.[1]

IEEFA Perspective on Capacity Mechanism

IEEFA is concerned that the proposed capacity mechanism will make it more difficult and more costly to achieve emissions reductions required to align with the Paris Agreement, to which Australia is a signatory.

The Energy Security Board (ESB) proposes to pay generators based on capacity available in "at-risk periods." The ESB's definition of "at-risk periods" is focused on periods of time when wind and solar generation is low (contrary to the ESB's stated principle of technology neutrality), so therefore wind and solar generators are likely to receive minimal capacity credits. Thus, there is a high risk that the mechanism will overcompensate fossil fuel generators and undercompensate low emissions generators.

International experience shows that in general, capacity markets favour resources with lower fixed costs and higher operating costs, as they can offer capacity at the lowest cost and thus are more likely to receive capacity credit revenue. These models typically favour coal and gas generators, and disadvantage renewables and other low emission energy resources. They also tend to favour existing generators (with largely depreciated assets) over new entrants.

As research published in Nature Energy detailed:

> *"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."*[2]

With increased levels of wind and solar in Australia's National Electricity Market (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 5 minute intervals instead of 30 minutes, which

[1] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.
[2] Jacob Mays, David P. Morton & Richard P. O'Neill. Asymmetric risk and fuel neutrality in electricity capacity markets. 28 October 2019.

began last year.

The ESB's proposed capacity payment reflects a move in the opposite direction - towards a central planner (or retailer) attempting to guess at least a year in advance (and possibly greater) how much power supply will be needed, over what time periods, and from what types of power plants. This could worsen reliability because it is likely to encourage the wrong types of power plants to remain operating (the expensive aged ones) while deterring the entry of newer, more reliable and more flexible power plants that are better suited to a grid with increasingly high levels of wind and solar.[3]

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 financial viability of several coal generators in the NEM is under threat. As such, there is a risk of abrupt, unexpected closure.** It is therefore vital to manage coal exit uncertainty.[4]

2. **Almost 6,500 megawatts (MW) of new known dispatchable capacity is due to be added to the NEM between 2017 and 2027.** This is 1.9 times the aggregated capacity of the coal power stations – Yallourn, Callide B and Vales Point B – scheduled to close soon after 2027. Knowing this large amount of dispatchable capacity is coming online means that the potential impact of abrupt coal exit is contained and manageable, buying energy planners time to manage the exit of coal generators in an effective manner without threatening reliability.[5]

3. **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 does not address the underlying reasons for why governments are regularly intervening in the electricity market.[6]

4. **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,

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[3] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[4] IEEFA. Fast Erosion of Coal Plant Profits in the National Electricity Market. February 2021.
[5] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[6] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.

indicates annual payments from consumers to generators of $2.9 billion to $6.9 billion a year.[7]

5. **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.[8]

6. **There are many other more targeted options to deal with the challenges facing the NEM while reducing emissions.**[9] Alternative options include:

    - Strengthening the regulatory regime for ensuring owners of large and aged power stations give at least three and half years notice of exit based on providing an upfront bond -- rather than depending on application of penalties only once a breach occurs (which is the current case). This should be complemented by the use of financial and engineering audits of these large, aged power stations every three years - to undertake stress-tests of their ability to maintain reliable operation, and to assess their risk of abrupt exit.

    - Enacting legislation that sets out a schedule for coal generating units to be steadily retired once set amounts of new reliable replacement capacity are built. This will give investors in new capacity enhanced clarity and incentive to build new plants. Such investments will be primarily guided by expected returns in the electricity market, and should allow investors wide discretion on the choice of plant technology that best suits market needs. The specific order in which coal units are retired can be determined through an array of alternative methods which could include voluntary nomination by owners (likely if the plant is loss-making and the notice period bond is returned); an auction process where a plant's units are paid to retire; or regulatory criteria (e.g. evaluation of their relative reliability or unplanned outage risk; their emissions intensity, age).

    - Providing a floor price underwriting mechanism to encourage new competitors to build new dispatchable capacity. This could be modelled along the lines of the Australian Competition and Consumer Commission's (ACCC) 2018 electricity market review recommendation where a new entrant, before project commencement, would be expected to first secure a 3 year contract to provide firmed power supply to customers outside of the major government and private sector retailers. The price floor would then cover years four to seven of the plant's life.

    - Implementing a long-term mandatory obligation for electricity retailers or generators to reduce emissions, with a mechanism for flexibility via trading. The emission target should be based on a steady reduction in annual

[7] IEEFA. Energy Security Board's Capacity Payment: Burden on Households. August 2021.
[8] RenewEconomy. The dubious modelling behind the Energy Security Board's capacity market proposal. 8 September 2021.
[9] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.

emissions in line with the States' net zero by 2050 targets, with interim targets reducing emissions well below an expected business-as-usual trajectory.

- Avoiding contracts with individual generators, as per the Victorian Government arrangement with the Yallourn Power Station. If such agreements need to be entered into, they should include a schedule (detailed publicly) for faster retirement of generating units than originally agreed, based on when suitable replacement capacity comes online. That replacement capacity should not need to come from the owner of the generator which is party to the support contract.

- Augmenting the existing energy-only market with enhanced energy reserve mechanisms (e.g. an operating reserve) if merited, based on an evaluation of the risk to reliability from abrupt coal exit in advance of completion of Snowy 2.0.

- Delivering additional flexibility to the grid by expanding the demand response mechanism to aggregated participants, enabling residential loads to participate. This has the potential to provide significant additional flexibility to the NEM For example, air conditioner controls in NSW alone could realistically deliver 700MW of peak demand reductions by 2025. Overall, Direct Load Control in NSW could deliver up to 1,437MW of routine demand reductions during summer in 2035.[10]

IEEFA recommends that all options be delivered to the ministers in December 2022, including a cost benefit analysis for each option and a critique of how each option would address the challenges facing the NEM and reduce emissions.

[10] Energy Savings Industry Association. Analysis of COAG E3 program's roll-out of demand response controls on electrical appliances.

Answers to ESB Consultation Questions

1. Considering the design principles from Energy Ministers, are there any additional assessment criteria the Board should use when assessing identified issues and possible solutions?

The assessment criteria doesn't include a reference to cost minimisation. It is key that any mechanism introduced is efficient, and that it minimises both the cost to the system and the cost to consumers. This should be explicitly included in the assessment criteria.

The technology neutrality assessment criteria is a good idea, however the way it is proposed raises issues around how the capacity market is currently being designed. The ESB is planning to identify certain "at-risk" time periods using modelling. From that, capacity credits would be awarded to a generator based *not* on the electricity they actually produce, but rather on an assessment of the maximum electricity they could potentially produce during periods of time that energy officials believe the system could face risks of supply outages ("at-risk periods"). The ESB's definition of "at-risk periods" is focused on periods of time when wind and solar generation is low (for example the "prolonged renewable droughts"), meaning that wind and solar generators are likely to receive limited capacity credits. As such, this is not a technology neutral approach, as it is designed to provide a lower level of support to wind and solar than other technologies.

2. Do you agree with the proposed approach to how the ESB will incorporate and address the Energy Ministers' design principles?

IEEFA does not agree with the proposed approach the ESB has laid out.

Firstly, the problems to be solved in the NEM must be clearly defined and presented. From IEEFA's readings of previous ESB papers throughout the Post 2025 Market Design process, the key problems to be solved include: 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. [11]

IEEFA has already outlined many solutions to solve these problems, which can be found in our report: **There is a Better Way to Manage Coal Closures Than Paying to Delay Them.**[12]

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[11] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.

[12] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.

The ESB has also laid out a selection of options to solve the problems in the NEM, including operating reserves, scarcity price adders, and others.

All of these options should be assessed against how well they solve the problems in the NEM, and a cost benefit analysis completed for each option. To IEEFA's knowledge, this step does not appear to have been undertaken.

We recommend that all options be delivered to the ministers in December 2022, including a cost benefit analysis for each option and a critique of how each option would address the challenges facing the NEM and reduce emissions.

Furthermore, many stakeholders, including retailers, universities, retailers, generators, think tanks and others, have expressed concern about the proposed Physical Retailer Reliability Obligation and the capacity market proposals.[13] 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.

3. Are there specific design choices from international capacity markets the ESB should explore in a NEM context?

See below.

4. Are there other international examples of valuing capacity that the ESB should consider?

If the ESB decides that the capacity market approach is ideal for solving the problems facing the NEM, then international capacity market design choices that the ESB should consider for NEM application include:

- Some capacity markets only allow capacity under a certain emissions intensity limit to qualify for capacity credits (e.g. the EU limit of 550g CO2/kWh applying from 2025 onwards). Emissions intensity limits on capacity should be considered in the context of any potential NEM capacity mechanism to ensure it meets the principle set out by Energy Ministers that the mechanism support "continued emission reduction". It would also assist in meeting the Energy Ministers' principle that the mechanism "provide greater certainty around closure dates of exiting generation".

- Some countries use a capacity mechanism in tandem with other policies as a tool to phase out coal generators and reduce emissions (e.g. the UK implemented a capacity market, carbon price floor and emissions performance standards). This approach should be considered as part of meeting the Energy Minister's principles that the mechanism should "provide greater certainty around closure dates of exiting generation" as well as "continued emission reduction".

[13] IEEFA. ESB Submissions and Directions Paper Summary. January 2021.

- Interconnectors and demand side response can participate in the UK's capacity market. These should also be included in any NEM capacity mechanism.

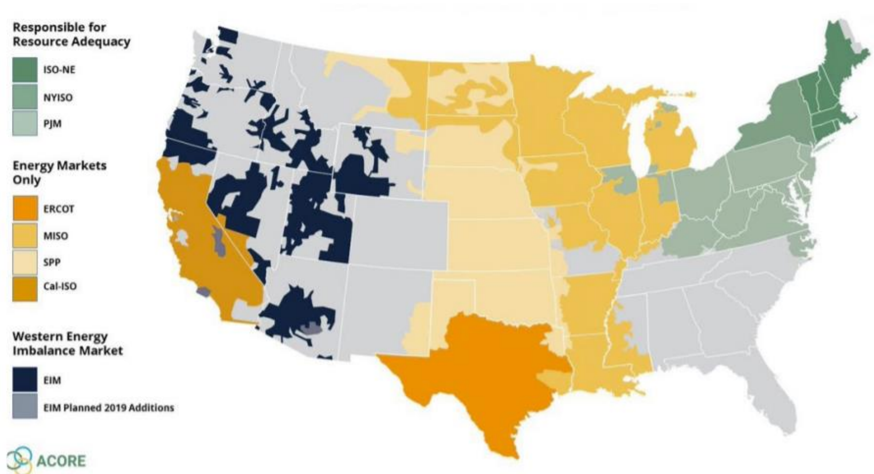
- Some capacity markets clearly distinguish between new plants and existing plants (e.g. the UK). They provide longer contracts to new entrants, compared to existing plants. This could be more effective in incentivising new entrants. Used in tandem with emissions intensity limits on qualifying capacity, it could better encourage investment in new, low emissions capacity.

- Some countries have decided *not* to implement a capacity market, and to instead implement a coal phasedown mechanism (e.g. Germany). Other non-capacity mechanism options should be considered to solve the problems facing the NEM.

U.S.

In the U.S., capacity markets are used by grid operators in New England (ISO-NE), New York (NYISO), and the PJM market that covers much of the Mid-Atlantic and Great Lakes states.[14] The Californian energy market (CAISO) does not have a centralized capacity market, however it does have a mandatory resource adequacy requirement (a mechanism similar to the Retailer Reliability Obligation (RRO)).[15] [16]

Figure 1: U.S. Centralized Power Markets

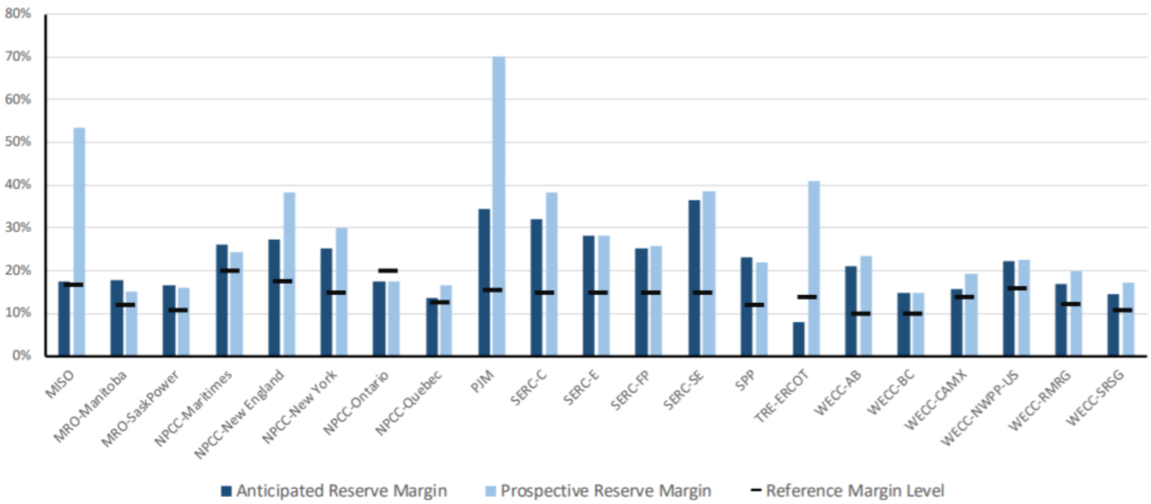


Source: Grid Strategies.[17]

[14] Grid Strategies. Too much of the wrong thing: the need for capacity market replacement or reform. November 2019.
[15] Sustainable FERC Project. Navigating CAISO. Accessed 18 January 2022.
[16] Greg Williams, AEMC. Profiling the capacity market debate. Accessed 18 January 2022.
[17] Grid Strategies. Too much of the wrong thing: the need for capacity market replacement or reform. November 2019.

These three regions with capacity markets have had some of the largest surpluses of generating capacity in the U.S., as shown below.[18]

Figure 2: U.S. Generating Capacity Surplus by Market



Source: ESIG.[19]

A survey of U.S. capacity market experts found that of the respondents, *41% advised EU member states against implementing capacity markets, 5% had no opinion, and the remainder provided suggestions for improving capacity markets*.[20] The results showed a clear preference towards an energy-only market for providing adequate signals for investment.

The survey found that capacity market design in the U.S. has faced a number of issues, including the role of demand response, whether locational constraints should be imposed, how far forward the markets should be run, and whether separate markets should be created for flexible capacity to back up variable renewables.[21]

In the survey, U.S. experts criticised capacity markets for 4 main reasons:

1. Differing designs of neighbouring capacity markets led to mismatch
2. Continuous changes in administrative rules of capacity markets increased uncertainty and regulatory risk for investors
3. Market power was exercised, including bidding above the marginal cost and

[18] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.
[19] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.
[20] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016.
[21] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016

then "double dipping" (selling capacity credits then exporting the power from the same generator to a neighbouring market with higher prices)

4. Concern that some of the generators that received capacity payments may not be able to honour their commitments during a scarcity event.[22]

U.S. experts stated that the three capacity markets achieved the goals of providing the required reserve margin, but in an economically inefficient way (54% agreed, 23% disagreed, and 23% had no opinion). Several respondents suggested that capacity markets lead to surplus generation capacity at the cost of the consumer.[23]

> *"The introduction of capacity markets has not led to an increase in consumer benefit, according to the respondents, as any potential benefit of the increased supply on electricity prices is offset by the additional costs arising from the capacity market itself. These costs appear to be mainly due to a higher reserve margin than would be economically optimal. Moreover, with respect to energy security, the availability of the additional generation resources remains uncertain."*[24]

A review of the PJM capacity market in 2020 found that it was not competitive.[25] That capacity market has been criticized because "auctions are biased toward larger power plants and don't offer enough flexibility to states such as Illinois with ambitious renewable goals."[26] Further, PJM capacity market rules undercount renewables and storage resources' value:

- PJM requires storage resources to be able to discharge for at least 10 hours to qualify as capacity resources[27]

- PJM counts resources' capacity contribution based on what they can provide across the entire year, even though solar and some demand response resources provide more capacity during summer peak demand periods, while wind provides more capacity during winter peak demand periods.[28]

UK

In the UK, the amount of power generated from coal in 2020 was 96% lower than in 2005.[29] The federal Government introduced the Carbon Price Floor in 2013 which

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[22] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016.
[23] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016.
[24] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016.
[25] Monitoring Analytics. 2020 State of the Market Report for PJM. 29 March 2021
[26] Energy News – David Thill. PJM Capacity Market. March 2019
[27] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.
[28] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.
[29] Ember Global Electricity Review 2021 dataset

decreased the competitiveness of high-emitting coal plants. In parallel to this mechanism, emissions performance standards (EPS) were also implemented in 2013. The standards set a limit on the emissions of new power plants at 450g CO_2-e per kW – similar to the emissions intensity of gas-fired generation, and approximately half the emissions intensity of a coal plant.[30]

The cost to comply with these regulations, and competition from renewables and gas, made new coal investments unviable. In 2015, the government announced that emissions performance standards would be extended to existing coal generators in 2025. This resulted in owners bringing forward planned coal plant closure dates, as the ageing coal generators were struggling to compete against renewables and gas – it also provided a clear date by which they needed to exit.[31] The final coal generators in the UK are predicted to close by 2024.[32]

The UK introduced a centralised capacity market in 2014. It involves a centrally managed auction process to procure capacity each year. New and existing generators, demand side response, interconnectors and storage operators can receive steady payments from National Grid during the term of their respective agreements, in return for a commitment to deliver electricity (or reduce demand) at times of system stress. “Contracts are available for up to 15 years for new facilities, for up to three years for refurbished facilities and for one year for existing facilities. Whether a facility will fall into the "new" or "refurbished" categories will depend primarily on their planned levels of capital expenditure which must meet a per/MW threshold.”[33]

An EU court ruling in 2018 forced the UK to halt payments under its capacity mechanism as the capacity market was deemed illegal. The European Court of Justice (ECJ) ruled that the European Commission had failed to launch a proper investigation into the UK’s capacity market when it cleared the scheme for state aid approval.[34] [35] It was then reinstated in 2019.[36]

The UK capacity market was introduced to maintain reliability while the grid transitioned to low carbon sources, but evidence shows that it was a backward step – it moved the country away from a more democratic energy system including local, small-scale generation, to a centralised, rigid scheme rewarding the biggest, most heavily polluting incumbents.

The UK capacity market had a cumulative cost from 2014 - 2018 of £3.8 billion – 75% of payments went to existing coal, gas and nuclear plants, and only 10% to

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[30] Blueprint Institute. Phasing down gracefully. 21 December 2020.
[31] Blueprint Institute. Phasing down gracefully. 21 December 2020.
[32] The UK Department for Business, Energy and Industrial Strategy. Capacity Market: Improving delivery assurance and early action to align with net zero. July 2021.
[33] Whitecase. UK Capacity Market suspended after European General Court ruling – A Detailed Analysis & What Next? 21 November 2018.
[34] InfoCuria case-law. Judgement of the General Court (Third Chamber, Extended Composition). 15 November 2018.
[35] Lexology. ECJ rules UK capacity market 'over competitive and illegal' 15 November 2018.
[36] Reuters. UK to reinstate power capacity market scheme after EU approval. 24 October 2019.

modern assets. It was found that most existing power plants remunerated under the scheme would have remained available regardless of the scheme.[37]

The biggest winners in 2018/19 were existing gas generators.[38] Two thirds of capacity with agreements for Delivery Year 2024/25 are also gas fuelled.[39]

The UK government is now working on aligning the capacity market with net zero, recognizing it has traditionally favoured fossil fuel generators. The UK government stated:

> *"Whilst the Capacity Market has seen growing participation in recent years from low carbon forms of generation such as wind and solar renewables, electricity storage, and some types of Demand Side Response (DSR), it has historically secured predominantly carbon intensive forms of generation, particularly unabated gas-fired generation. For example, about two thirds of capacity with agreements for Delivery Year 2024/25 is gas fuelled."*[40]

The UK government is also looking for ways to ensure that the capacity required can be delivered at the right time, stating:

> *"It is also important that we have confidence that capacity secured through the Capacity Market will be available when called upon to deliver in a System Stress Event. Indeed, the need for this confidence was illustrated by the greater non-delivery of capacity and by the tighter margins observed over winter 2020/21."*[41]

In June 2019, the European Commission introduced regulation (EU) 2019/943 limiting the emission intensity of generators that should qualify for capacity payments, stating:

> *"From 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity and more than 350 kg CO2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism."*[42]

The UK government also applied these carbon emissions limits in its capacity

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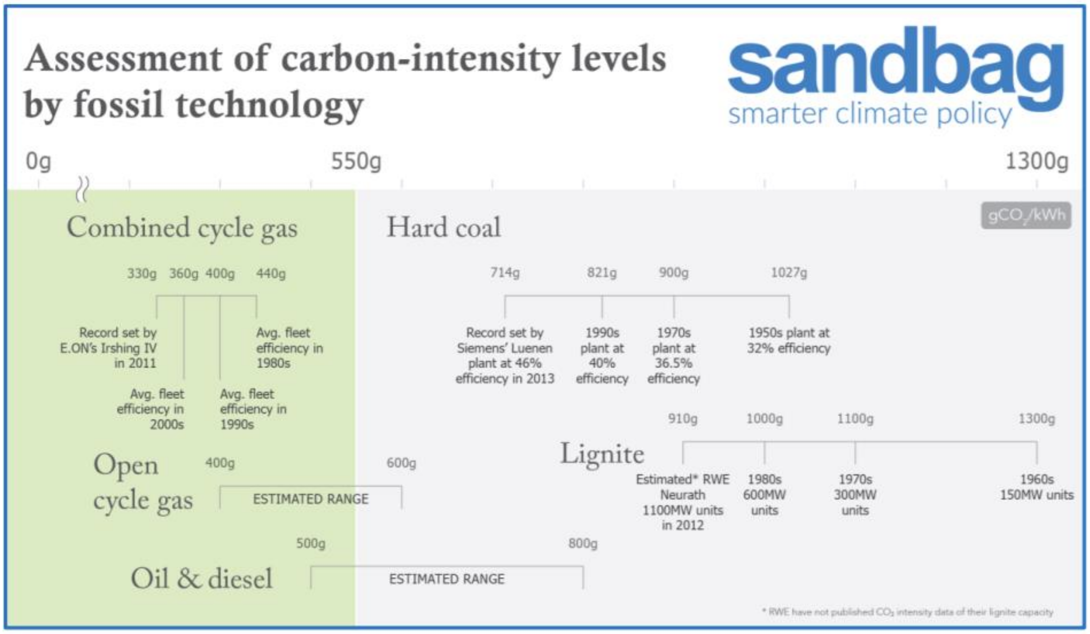
[37] IEEFA. Time to Rethink Britain's Capacity Market. October 2018.
[38] Carbon Brief. Old coal and gas plants won largest share of capacity market, final results confirm. 5 January 2015.
[39] The UK Department for Business, Energy and Industrial Strategy. Capacity Market: Improving delivery assurance and early action to align with net zero. July 2021.
[40] The UK Department for Business, Energy and Industrial Strategy. Capacity Market: Improving delivery assurance and early action to align with net zero. July 2021.
[41] The UK Department for Business, Energy and Industrial Strategy. Capacity Market: Improving delivery assurance and early action to align with net zero. July 2021.
[42] European Parliament and Council. Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal Market for Electricity

mechanism.[43] These emissions limits will still include most gas generators as shown below.

Figure 3: Assessment of Carbon-intensity Levels by Fossil Technology



Source: Ember.[44]

France

France's decentralised capacity market has been quoted as the basis for the ESB's design of the NEM's decentralised capacity market.[45]

France launched its capacity market in 2016, aiming to ensure that there was enough capacity to meet winter demand and to enable generators to cover their fixed costs.[46]

It has however seen volatile prices. In May 2019 prices crashed to EUR 0/MW, down from EUR 18,000/MW in December 2018.[47]

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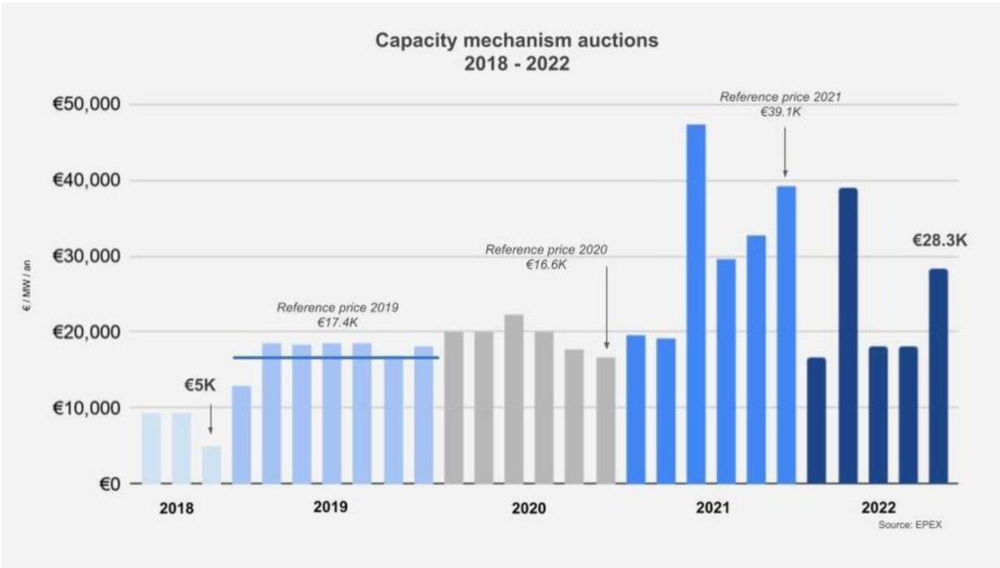
[43] The UK Department for Business, Energy and Industrial Strategy. Carbon Emissions Limits in the Capacity Market. July 2021.
[44] Ember Climate & Sandbag Smarter Climate Policy. Capacity payments and 550g. 1 June 2017.
[45] RenewEconomy. Transcript: Energy Insiders interview with ESB chair Kerry Schott. 30 April 2021.
[46] Herman Moestue, Montel. French energy regulator mulls capacity market reform. 25 September 2019.
[47] Herman Moestue, Montel. French energy regulator mulls capacity market reform. 25 September 2019.

Figure 4: France's Capacity Mechanism Auctions 2018 - 2022



Source: Flexcity.[48]

Furthermore, France's regulator, the CRE (Energy Regulatory Commission) has criticised the French capacity mechanism for enabling "particular behaviour among some actors" and for failing to incentivise suppliers to demand guarantees before the delivery year.[49]

The CRE has indicated interest in reforming its capacity market to move to a more centralised mechanism, similar to those in place in the UK, Ireland and Poland, within a few years.[50] IEEFA is not aware of the current status of reform.

France also has a coal phase-out plan, aiming to exit coal-fired generation by 2025.[51]

Poland

In 2018, Poland implemented a centralized capacity market. The goals were to ensure appropriate funding for existing and new power generation units to improve long-term energy security.[52]

However, a review of Poland's capacity market since its inception found that it did

[48] Flexcity. Increase in the prices of the French Capacity Mechanism auction. 16 March 2021.
[49] Herman Moestue, Montel. French energy regulator mulls capacity market reform. 25 September 2019.
[50] Herman Moestue, Montel. French energy regulator mulls capacity market reform. 25 September 2019.
[51] Argus media. G7 countries agree to accelerate coal phase-out. 21 May 2021.
[52] 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.

not bring incentives for investments in new power generation units:[53]

> *"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 construction, and the investment decisions were made long before the implementation of the capacity market mechanism."*[54]

Coal will be ineligible for capacity payments from 2025, as a limit of 550g CO2/kWh will be imposed by the Polish Electricity Networks from 2025 onwards.[55] This is in line with EU regulations which state that capacity market support cannot go to plants emitting above 550g CO2/kWh from 2025 onwards.[56]

A 2021 analysis of how Poland's energy system would change under a capacity market (taking into account the assumption that coal-fired units cannot receive capacity market support from 2025) 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."*[57]

Italy

In Italy's capacity mechanism, new build plants are eligible for up to 15 years of support. Coal plants are excluded from the scheme.[58] Italy also has a coal phase-out plan, aiming to exit coal-fired generation by 2025.[59]

Western Australia

Western Australia introduced a centralised capacity market in 2005-06 amid fears of a future power shortage. Today, prices in Western Australia are now significantly above national average and renewable energy uptake has been slower than other states in Australia.

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[53] 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.
[54] 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.
[55] https://www.iea.org/policies/12654-emissions-limit-on-the-capacity-market-regulations
[56] European Parliament and Council. Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal Market for Electricity
[57] Aleksandra Komorowska. Can Decarbonisation and Capacity Market Go Together? The Case Study of Poland. 20 August 2021.
[58] https://timera-energy.com/a-tour-of-european-capacity-markets/
[59] Argus media. G7 countries agree to accelerate coal phase-out. 21 May 2021.

The Western Australia capacity market has had issues. The payments to power plants under the Reserve Capacity Mechanism were based on predictions of future demand requirements. However, the Australian Energy Market Operator (AEMO) overestimated the required capacity, resulting in overcapacity and higher bills for consumers.[60]

Further, Western Australia has faced energy security issues despite the capacity mechanism. Western Australia has launched an independent investigation into a series of blackouts that struck the state's main grid over the Christmas 2021 period and left tens of thousands of households without power during a four-day heatwave.[61]

A notable aspect about the Western Australian energy market is that the price cap is lower than $600/MWh – much lower than the NEM price cap of $15,100/MWh.

Germany

Germany decided not to implement a capacity market in 2016, in response to discussion with stakeholders and recommendations from experts.[62]

On 14 August 2020 Germany passed an Act to Reduce and End Coal-Powered Energy and Amend Other Laws (Coal Phase-Out Act) to end coal-fired power generation by 2038 at the latest.[63]

It agreed on a shutdown schedule for lignite (brown coal) power plants and compensation payments for the operators. A total of 4.35 billion euros in compensation will be paid for the planned lignite shutdowns by 2030.[64]

For anthracite (hard coal), the Coal Phase-Out Act proposed auctions for plant operators to remove capacity from the grid according to the government's schedule. In the auctions, coal generator operators tender capacity volumes to be taken offline, and how much money they require for the closure. There are maximum renumeration volumes per MW set for each round of auctions which are set to decrease with each auction round (encouraging early participation in the scheme) (Figure 5). After 2027, forced shutdowns will occur. [65] [66]

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[60] AEMO. Benchmark Reserve Capacity Price. Accessed 18 January 2022.
[61] RenewEconomy. "Unmanaged energy": WA gears up for solar switch-off rules, to probe Christmas blackouts. 31 January 2022.
[62] Pradyumna C Bhagwat, Laurens de Vries and Benjamin F. Hobbs. Expert Survey on capacity markets in the US: Lessons for the EU. 2016. And: Clean Energy Wire. Gas industry calls for capacity market debate as Germany exits nuclear and coal. 11 February 2020. U,
[63] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.
[64] Clean Energy Wire. Spelling out the coal exit – Germany's phase-out plan. 3 July 2020.
[65] Clean Energy Wire. Spelling out the coal exit – Germany's phase-out plan. 3 July 2020.
[66] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.

Figure 5: Auctions Price Caps for Hard Coal Capacity To Be Closed

Tender Year	Auction price cap (EUR/MW)
2020	165.000
2021	155,000
2022	155,000
2023	116,000
2024	107,000
2025	98,000
2026	89,000

Source: Ember.[67]

The first auction of hard coal plants was oversubscribed. The total amount of compensation was €317 million. The scheme has been criticised for paying too much compensation to loss-making hard coal plants that are generating little electricity. An analysis by Ember found that nearly all the German hard coal fleet has been running at a loss since the end of 2018, collectively losing over €1 billion. And while the scheme continues to aim for a 2038 closure, it should be aiming for 2030 to align with the Paris Agreement.[68]

In parallel with the coal exit plan, the German Renewable Energy Sources Act was amended with the goal to raise the percentage of renewables to 65% by 2030.[69] The government also introduced various support schemes including:

- Workers aged over 58 who lose their jobs when plants are decommissioned will receive compensation for a maximum of 5 years until they are eligible for their pension.[70]

- Lignite-coal regions will receive financial aid of up to €14 billion.[71]

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[67] Ember Climate. German State Awards €317 Million To Loss-Making Coal Plants. 8 December 2020.
[68] Ember Climate. German State Awards €317 Million To Loss-Making Coal Plants. 8 December 2020.
[69] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.
[70] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.
[71] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.

- Hard-coal regions will receive financial aid of up to €1.09 billion.[72]

Denmark

Denmark does not have a capacity market yet it has 61% of its electricity generated by wind and solar in 2020. [73] High levels of variable renewable penetration have been reached without a capacity market. Denmark expects to phase out coal by 2028. [74]

5. What design choices do stakeholders consider would work well for the NEM?

The case for a capacity mechanism in the NEM has not been proven. If the ESB does continue to design a capacity mechanism, the below design choice should be considered alongside the other design choices mentioned by the ESB.

- How will emissions from the electricity sector be minimised?

6. Are there design choices from these international examples that stakeholders consider will not work well in the context of the NEM?

The case for a capacity mechanism in the NEM has not been proven. If the ESB does continue to design a capacity mechanism, the below design choices from international examples will *not* work well in the context of the NEM.

- The PJM capacity market requires storage resources to be able to discharge for at least 10 hours to qualify for capacity payments.[75] This would exclude most batteries, and this design choice should *not* be implemented. Care should be taken to ensure batteries qualify for capacity payments.

- The PJM capacity market counts a resources' capacity contribution based on what it can provide across an entire year.[76] This is a blunt instrument and would *not* work well in the NEM.

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[72] Library of Congress. Germany: Law on Phasing-Out Coal-Powered Energy by 2038 Enters into Force. 31 August 2020.
[73] Ember Climate. Top 15 Wind and Solar Power Countries. July 2021.
[74] Danski Industri. Global Danish export potential when coal is phased out of electricity production. 2021.
[75] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.
[76] ESIG: Michael Goggin, Grid Strategies. Capacity Markets: The Way of the Future or the Way of the Past? March 27 2020.

7. Do you have any views on whether there are other design areas the ESB will need to consider in the design of a capacity mechanism?

The issue of emissions has not been thoroughly considered in the ESB capacity market initiation paper, and will need to be explored in depth.[77]

In the present stage of design of the capacity mechanism, it appears that plants of all emissions intensity would qualify for capacity payments. Any energy market mechanisms implemented should act to reduce emissions and should *not* provide payments primarily to emissions intensive generators.

The ESB could consider many other options apart from a capacity mechanism in order to ensure a smooth transition to a low emissions grid. These have been explored in a previous IEEFA report.[78]

8. Has the ESB accurately reflected the trade-offs to be considered for each core design area?

There are trade-offs that cannot be resolved between a decentralised model and a centralised model for the capacity mechanism.

A capacity mechanism in which retailers forecast the required capacity, and are responsible for procuring it, would not significantly change the underlying dynamics in the energy-only market.

At present, some retailers are choosing not to contract long term. They could largely continue this practice even with a capacity mechanism in place. For example, if they were required to contract for capacity 4 years in advance, and 1 year in advance they could buy extra capacity credits, they may buy less capacity credits than their required capacity 4 years in advance (T-4) and buy up a large amount of additional capacity credits only 1 year in advance (T-1). This would not provide the long-term capacity investment signals desired.

In a model in which retailers are forecasting and procuring their capacity requirements, it will be difficult to account for customer churn and growth.

Furthermore, in a model in which retailers were forecasting their capacity requirements *and* contracting to meet that, it would be difficult to assess compliance before the year of concern because the retailer has set their own "capacity target". Some amount of centralised forecasting would always be needed to check the retailers' compliance before the year of concern. Compliance would need to be assessed ex-post – as mentioned by the ESB.

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[77] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.
[78] IEEFA. There is a Better Way to Manage Coal Closures Than Paying to Delay Them. September 2021.

Moving to a capacity mechanism in which AEMO forecasts the capacity and compliance is assessed ex-ante could provide greater investment certainty as there would likely be more clarity around the amount of capacity to be procured, further into the future. However, this model is dependent on AEMO's forecasting capability and tendencies. For instance, AEMO could forecast high capacity requirements to err on the side of caution, leading to an over-procurement of capacity. Thus, this could be a higher cost model. The capacity market in Western Australia faced this issue – AEMO forecast high capacity requirements leading to an over-procurement of capacity in the Reserve Capacity Mechanism, and therefore unnecessary cost.

In summary, a retailer-led model might provide less investment confidence and certainty. A centralised model could provide better investment confidence and certainty but would likely be higher cost. These trade-offs are irresolvable.

Other options to directly resolve the problems that the ESB has identified should be explored, rather than relying on a capacity mechanism.

9. Do stakeholders have views on the definition of reliability at-risk periods?

The ESB definition of "at-risk" periods is largely focused on defining periods of low wind and solar generation. This means the mechanism would provide minimal payments to these fuel sources and would be inherently biased against them by explicit design.

The ESB definition of "at-risk" periods also appears to lack a sound evidence base– to IEEFA's understanding, no modelling has been released to quantify or explain the "at-risk" periods that have been a focus of the discussion so far – the so-called "prolonged renewable droughts" and the "unavailability of wind and solar resources".

The focus should be on defining what the "at-risk" periods are, when the "at-risk" periods could be, and how long they would be, and only then, if they are deemed a significant problem, designing a mechanism that will solve this problem. A general capacity market mechanism will not ensure that capacity is available in the "at-risk" periods because it will not be able to accurately forecast (years in advance) what those "at-risk" periods actually are.

Any "at-risk" period is best captured by the energy market in which price changes on a 5 minute basis and takes into account all of the market dynamics – ramping, generator maintenance, weather conditions, transmission, reserves etc.

Trying to forecast when the "at-risk" periods would be very challenging and fraught. There are frequent unexpected changes in supply and demand that will not be able to be predicted – due to unexpected failures in the system, unexpected weather patterns etc.

The energy market, rather than a capacity market, should be utilised to make sure energy is available in "at-risk" periods. Other options could also be explored to ensure reliability, such as a strategic reserve, operating reserve, adding penalties for being short of energy or ancillary services at an administered cost of non-supply[79], and other options which we have explored in a previous IEEFA report.[80]

We would also note that fuel types other than wind and solar can suffer from extended periods of inadequate supply, which have been completely ignored by the ESB.

The Millennium Drought that led to very low dam water storage levels by 2007 - 2008 meant output from hydro power plants and also several coal power plants (which depend on large quantities of water for cooling purposes) needed to be curtailed. The drought was so severe that several coal generating units were withdrawn from service, power adequacy was threatened, and prices spiked to some of the highest levels experienced by the NEM.

In the case of gas power plants, we have seen two cases of major extended gas supply shortages in Australia. The first was the explosion of the Longford gas processing plant in Victoria in 1998 which resulted in severe gas shortages for two weeks. The second case was the explosion of the Varanus Island gas processing plant in Western Australia in 2008. This plant took three months to be repaired and also led to major gas shortages for the state.

The ESB's failure to consider these incredibly significant fuel supply outages which unfolded in relatively recent history is very odd given the extensive consideration given to shortages of wind and solar resources supposedly creating energy adequacy problems. This omission of these real-world energy adequacy events 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.

10. Which of the above derating methods would work best and why?

The energy market is best suited to manage any "derating" as it is in real-time and will capture all the energy market dynamics, rather than trying to approximate those years in advance and pay generators based on those approximations.

Using historical data or forward-looking simulations to estimate wind and solar contribution in the forecast "at-risk" periods, and derating their capacity based on that, is fraught.

IEEFA does not recommend the capacity mechanism approach. However, if it is continued, and a derating method is chosen, we provide the following comments.

> The ESB does not mention derating of gas plants due to supply issues including limited pipeline capacity or pipeline failures, or the nature of gas supply

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[79] Greg Williams, AEMC. Profiling the capacity market debate. Accessed 18 January 2022.
[80] IEEFA. There's a Better Way To Manage Coal Closures Than Paying To Delay Them. September 2021.

contracts held by power plants and their relative priority to access gas over other customers. However, this should be included in the derating methodology.

If the Longford gas processing plant suffered another explosion, and the NEM was supported by wind, solar, batteries and coal for some time, the capacity market would *not* have forecast nor adequately compensated generators for this "at-risk" period. Firstly, the ESB capacity mechanism would not have predicted this particular "at-risk" period, as due to its unexpected nature it was not forecastable. Secondly, under the ESB capacity mechanism, wind and solar would have been derated. Therefore, they would not have been compensated for their actual contribution during this genuine supply adequacy "at-risk" period. The energy market, on the other hand, would have adequately compensated generators for their actual production in such a situation.

The reliability of coal has also not been mentioned by the ESB as a derating factor, however this should be included in any derating method. AEMO published statistics on coal reliability in the ESOO2021, provided by the generators. In 2021, AEMO concluded that there is an increasing risk of coal plant failures, stating "While some plant improvements are expected in the near term, most generators are anticipating a trend of decreasing reliability in the longer term, increasing supply scarcity risk."[81]

The ESB has mentioned, further down in the capacity market initiation paper (page 26), that plants could be derated in later years if they are not available in the given "at-risk" periods – for example, if they had an outage.

> *"Part C of the ESB's Post-2025 Final Advice outlined how a rigorous ex-ante derating process, repeated for each delivery year, can provide an incentive for capacity providers to be available when required. Monitoring of performance by AEMO to feed into future availability assessments will ensure that resources have the incentive to be available, because providers who make a lesser contribution to resource adequacy than anticipated will receive a harsher de-rating factor in subsequent periods"*
> *- ESB.*[82]

In this scheme, unreliable plants could start with limited derating and thus could be overcompensated in the early years of the scheme.

In circumstances where a power plant is aged and close to being retired, and is probably one of the plants most at risk of a severe failure, applying derating based *not* on an ex-ante engineering risk assessment but rather solely on historical performance, creates a problematic asymmetric pay-off. Owners of such plants are unlikely to be disciplined to ensure reliability under such a regime. This is because the savings from reduced maintenance are certain, while the probability of a forced outage during an "at-risk" period as a result of economised maintenance will be far below 100%. In the event that an outage occurs in such a plant that leads to derating of capacity credits, the financial

[81] AEMO. 2021 Electricity Statement of Opportunities. August 2021.
[82] Energy Security Board. Capacity mechanism Project initiation paper. December 2021.

impact will be limited because the owner does not plan on running the generator for much longer after the event of a failure anyway. Under this ex-post derating regime, owners of aged power plants, who already face a strong incentive to contain maintenance expenditure, will just be tempted to try their luck on capacity credits knowing derating in later years has minimal consequences if it does occur.

There are many challenges with applying a derating 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.

11. Are there any other issues the ESB needs to consider when developing the approach to defining capacity?

The energy-only market effectively ensures retailers will cover their load when supply is short. They must hedge effectively, because an "at-risk" period could happen at any moment, and prices will reach very high levels. As the price changes every 5 minutes, the energy-only market caters for any imaginable "at-risk" period on a short timeframe. Any capacity mechanism will be an approximation and will not adequately compensate generators for their actual contribution to supply during "at-risk" periods.

The energy-only market should be used and could be enhanced if needed, rather than adding a capacity market. The case for a capacity market has *not* been proven.

12. In the context of the NEM, what do you consider to be the main advantages and disadvantages of the three options outlined above? [have copied options below]

Option 1a, the decentralised mechanism, is not likely to provide strong long-term signals for investment. This is because retailers might not contract for their full capacity requirement years in advance, and could just contract with additional capacity just 1 year in advance, to make sure they meet their capacity requirements and ensure they pass the ex-post compliance assessment.

Therefore, if the goal is to encourage long term contracting and provide strong long-term signals for investment, ex-ante compliance assessments are necessary.

In option 1b, with AEMO forecasting capacity requirements and retailers being responsible for procuring their allocated amount, retailers will make sure that they contract for the required capacity in advance of the year of concern, so that they pass the compliance assessment/s. This will provide longer term signals for investment in capacity. However, past experience with such types of markets suggests AEMO's forecast will be biased towards over-procurement of capacity, meaning that option 1b would likely be a higher cost option than option 1a.

Option 2, the fully centralised mechanism, could also have a higher cost than option 1a because it relies on AEMO's forecast of capacity and AEMO has historically shown it is likely to err on the side of caution. Customers will bear this cost.

In summary, a retailer-led model with ex-post enforcement doesn't provide a strong long-term investment signal, and the centralised ex-ante system carries risk we have seen with the Western Australian capacity market of having over-procurement of capacity and therefore high cost.

See answer to question 8 for further detail.

13. Which of the procurement approaches is best suited to the NEM and why?

IEEFA has not explored this question in detail. However, transparency is key (to ensuring equal information for all market participants and to ensuring consumers have visibility on their electricity bill make-up) and therefore auction or trading exchange platforms may be preferable over bilateral trading.

14. Which of the options outlined above can be expected to work best in the context of the NEM?

See answer to below (Question 15).

15. Are there any other issues the ESB needs to consider when developing the approach to transmission constraints and interconnectors?

Accounting for transmission constraints in the capacity mechanism is very complex. All sorts of distortions could be created in the market by getting this wrong. An energy-only market is best placed to manage dynamics related to constraints and interconnectors – a capacity mechanism will not be able to appropriately account for transmission constraints, as they are dynamic and depend on what is happening in the energy market at each given moment and each generator's location. Other non-capacity mechanism alternatives should be explored by the ESB to solve the problems facing the NEM, problems that the ESB has highlighted.

16. Are there any suggestions for other ways that market power could be mitigated?

No comment.

17. What kinds of market power issues are likely to be of the greatest concern?

No comment.

18. Are there any other issues the ESB needs to consider when developing the approach to market power mitigation?

No comment.

19. Which of the options for demand side incentives and compliance would work well, or not work well, and why?

No comment.

20. Which of the options for supply side incentives and compliance would work well, or not work well, and why?

Linking supply side incentives and compliance with wholesale market outcomes is an attempt to get the capacity market to emulate the energy-only market. Instead of trying to approximate the energy-only market with a capacity market, the energy-only market could be directly used to drive generators to contract to meet their peak load. Certain mechanisms could be implemented to ensure liable entities contract to meet their peak load within the existing energy market structures (such as adding penalties for being short of energy)[83]. A capacity mechanism is not required for this, and the case for change to a capacity mechanism is not evident.

21. Are there any other issues the ESB needs to consider when developing the approach to penalties and compliance?

See above.

[83] Greg Williams, AEMC. Profiling the capacity market debate. Accessed 18 January 2022.