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Energy Security Board Post 2025 Market Design Options

IEEFA Submission

Introduction

Thank you for accepting IEEFA's submission to the Energy Security Board (ESB) Post 2025 Market Design Options Paper, Part A and B, released on 30 April 2021[1].

According to the Energy Security Board (ESB), over 60% of existing thermal generating resources (mainly coal) in the National Electricity Market (NEM) are likely to exit over the next 2 decades as Australia transitions towards renewable generation (mainly wind and solar) and storage.

This transition away from large, synchronous 'always on' generators towards asynchronous, variable renewable generators requires a revisit of existing markets and mechanisms to ensure they are 'fit for purpose'.

While the ESB post 2025 market design reform is comprehensive and some initiatives are well-supported by stakeholders, others have been questioned. In the final stages of reform, it is key for the ESB to incorporate stakeholder feedback and to be forward thinking, to drive the NEM towards a low-emissions future consistent with the Australian government's commitment to the Paris Agreement and state government commitments to net zero by 2050.

Developing post 2025 market design reforms for the NEM is a formidable task given the context of fast technological change, the huge variation in stakeholder opinions, and ongoing inconsistent climate and energy policy in Australia.

One thing is clear: the NEM of the future must deliver reliable, secure and affordable power, with zero emissions. This can be achieved but there will be challenges along the way. If investment is focussed on preserving legacy practices and systems, it will only delay the transition and will cost consumers more.

It is therefore key for the ESB reforms to chart a clear path to a low-emissions, zero-inertia future with both large and small-scale renewable generation and storage. If well planned, such a system should be more affordable, reliable, secure and resilient, especially given the solar, wind and hydro resources available in Australia.

In addition, a decarbonised electricity system will facilitate the decarbonisation of the transport sector and will support the electrification of gas and many industrial processes.

[1] Energy Security Board. Post 2025 Market Design Options. 30 April 2021.

The recent IEA Net Zero by 2050 Roadmap for the Global Energy Sector has stated that for the world to meet net zero emissions by 2050, advanced economies need to decarbonise their electricity sector by 2035. The world needs to meet the following requirements:

- Phase out all subcritical coal-fired power plants by 2030
- Phase out all unabated coal-fired power plants by 2040
- Unabated natural gas-fired generation peaks by 2030 and is 90% lower by 2040.[2]

The post 2025 market design therefore needs to redesign the NEM to decarbonise the electricity sector by 2035, and to meet the other aforementioned IEA goals.

It is also important that post 2025 market design changes are accompanied by government policies and programs that both support the energy transition and ensure no one is left behind. While a large task, market design is only one dimension of the work needed to ensure Australia develops a more affordable, reliable, secure, resilient, zero-emissions, zero-inertia electricity system.

In particular, technical regulations need to be updated quickly and nimbly to keep up with changes in technology and to support innovation and competition. Policies and programs are also needed, especially to facilitate 'energy efficiency first' which is both vital and will lower the costs of the transition. Housing, building and appliance standards policy and programs are outside the NEM but significantly shape how much energy is used in Australia. In addition, energy efficiency policies and programs have large job creation potential and have been central to many countries' COVID-recovery economic plans.

Australia's national grid could be one of the first to fully transition to zero-emissions and zero-inertia and the country stands to benefit financially by exporting the technologies and know-how developed through the process.

[2] IEA. Net Zero by 2050: A Roadmap for the Global Energy Sector. May 2021.

Summary of our Submission

This submission covers resource adequacy mechanisms, integration of distributed energy resources and demand side participation, and essential system services workstreams. It makes the following main points, summarised below.

Resource Adequacy Mechanisms (RAMS)

SUPPORTED

- Increased information around mothballing and seasonal shutdowns.
- Expanding the notice of closure requirements to include mothballing.
- Contingent scenario planning.
- Consistent NEM-wide approach to jurisdictional underwriting.
- Monitoring reliability and overall costs.

SUPPORTED ONLY UNDER CERTAIN CONDITIONS

- The Orderly Exit Management Contract (OEMC) represents an intervention in the market. It should only be used as a last resort, with certain conditions placed on it - including that if there is enough replacement capacity built, the thermal generator should exit early. It should only be used in the case that the NEM does not have a regulated/incentivised framework to lock-in coal closure dates

NOT SUPPORTED

- The Retailer Reliability Obligation (RRO) modification proposals, either the physical or enhanced financial RRO, are not supported by IEEFA. The RRO will likely keep coal-fired power plants generating for longer. It does *not* reduce uncertainty; it delays the inevitable coal plant closures but does nothing to lock in the closure dates. It is *not* transparent. It will increase bills for electricity consumers, potentially significantly, as well as cool investment in new capacity. It is also *not* supported by many stakeholders, detailed further in the RAMs section.

RECOMMENDED

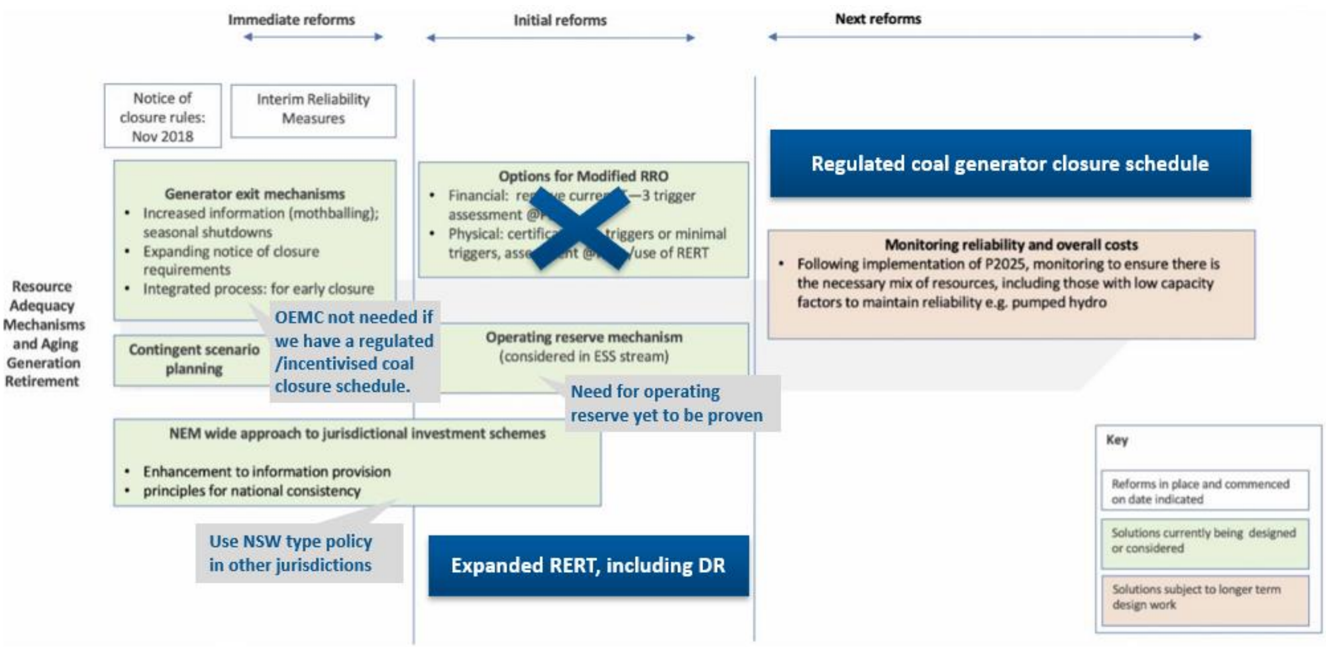
We recommend the ESB explores further mechanisms which have not yet been addressed in the Market Design Options Paper.

- An expanded Reliability and Emergency Reserve Trader (RERT), to include demand response providers that are not covered by the wholesale demand response mechanism, could be effective to prevent against a shortfall in capacity.

- The ESB could explore the potential use of the Market Liquidity Obligation (MLO), separated completely from the RRO, to provide more certainty around energy price and supply into the future. This could involve having the MLO triggered, separately from the RRO, requiring certain generators and certain energy users / retailers to enter into longer term electricity future contracts (e.g. 3-5 years). This would result in more transparency around future price and supply and would likely incentivise investment in generation.

- A regulated/incentivised coal closure schedule policy should be introduced (e.g. those recommended by the Blueprint Institute, ANU Professor Frank Jotzo, or another of similar type). **An orderly transition necessitates that coal closures be announced and locked-in well in advance with a legally enforceable framework of incentives and penalties that removes the uncertainty and risk around early closure.**

Figure 1: IEEFA Recommendation on RAMs



Source: ESB Options Paper RAMs timeline[3], with IEEFA edits added over the top to indicate IEEFA recommendation

[3] Energy Security Board. Post 2025 Market Design Options. 30 April 2021.

Integration of Distributed Energy Resources (DER) and Demand Side Participation

SUPPORTED

- IEEFA supports the proposed trader-services model whereby there would be one registration category and a 'modular' approach to obligations based on the services to be traded from each connection point (rather than the assets) and the ESB's consideration of an additional flexible trader model.

FURTHER WORK NEEDED

- There is no objection to non-scheduled resources (e.g. generation / demand / DER) providing voluntary self-forecasts of future behaviour or intentions under the proposed 'information only' voluntary Scheduled Lite. However, significant further work to develop this proposal is required e.g. evidence must be provided as to how the efficiency of operational decisions will be improved by Scheduled Lite and clarity is needed regarding under what circumstances Scheduled Lite would become mandatory. The Dispatchability model of Scheduled Lite is opposed on the grounds that it would impose significant costs on DER owners without a case as to the benefits to consumers.

NOT SUPPORTED

- IEEFA opposes any extension of the rooftop solar cutoff regulation and practice beyond South Australia and seeks a sunset date of the commencement of the operation of EnergyConnect for the existing AEMO process of cutting off solar.

- Proceeding with the Maturity Plan is opposed.

RECOMMENDED

- A comprehensive review of the National Energy Consumer Framework (NECF) is required building on the risk assessment tool developed by the Australian Energy Market Commission (AEMC).

- 'Network services' should be investigated through the AEMC's annual electricity network economic regulatory framework review (ENERF).

- Instead of the Maturity Plan, IEEFA recommends the ESB prioritise the following urgent reforms:

    - Fast-tracking of rule changes on the governance of DER technical standards by AEMC.

    - Greater resourcing and fast-tracking of DEIP work on Dynamic Operating Envelopes, including the AER taking responsibility for leading this work given the implications for DNSP connection agreements and the potential for improved consumer outcomes, including greater DER availability to participate in network support services.

- Putting modular definitions of market participants in place (as below).

- Planning for a zero-inertia system. This is now urgent (see IEEFA's recent report on this topic[4]).

Essential System Services (ESS)

IEEFA supports the ESB's proposed measures to implement mechanisms for delivery of essential systems services including frequency control, inertia, and system strength.

In particular, we encourage the unbundling of system services, and the establishment of efficient mechanisms for incentivising providers, on the basis that new flexible inverter-based resources are fully enabled. This approach will ensure that system security provision evolves in a way that underpins the energy transition and allows synchronous generation to exit the system on timeframes driven by economics, rather than being delayed due to dependence of the system.

The key points and recommendations that IEEFA makes are as follows:

- ESB should analyse scenarios for the optimal long-term end-state of the NEM, and then work backwards to ensure that proposed near term reforms and investments align with suitable pathways.

- A clear and well-defined workstream should be undertaken to prepare for a future scenario with inverter-based resources as the foundation of the NEM.

- The operational System Services Mechanism (SSM) should recognise that the transmission and distribution networks may need to be reconfigured into the future to enable a stable network that supports up to 100% inverter-based distributed generation assets.

- A Unit Commitment for Security (UCS) or SSM is supported for efficient lowest-cost procurement of ESS, where the design of a mechanism incentivises participation by inverter-based resources and demand response.

- There is no clear need for an operating reserves market for reliability or system security if efficient scheduled services are available, and such a market should only be considered in the future if benefits clearly outweigh costs.

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[4] IEEFA. Australia's Opportunity To Plan Ahead for a Secure Zero-Emissions Electricity Grid. March 2021.

- The plan for transitioning from legacy system security to future system security should be mapped out explicitly, which will help built investor confidence.

- There is no clear need for a voluntary day ahead market at the present, and further work on other reforms should take priority.

Part A

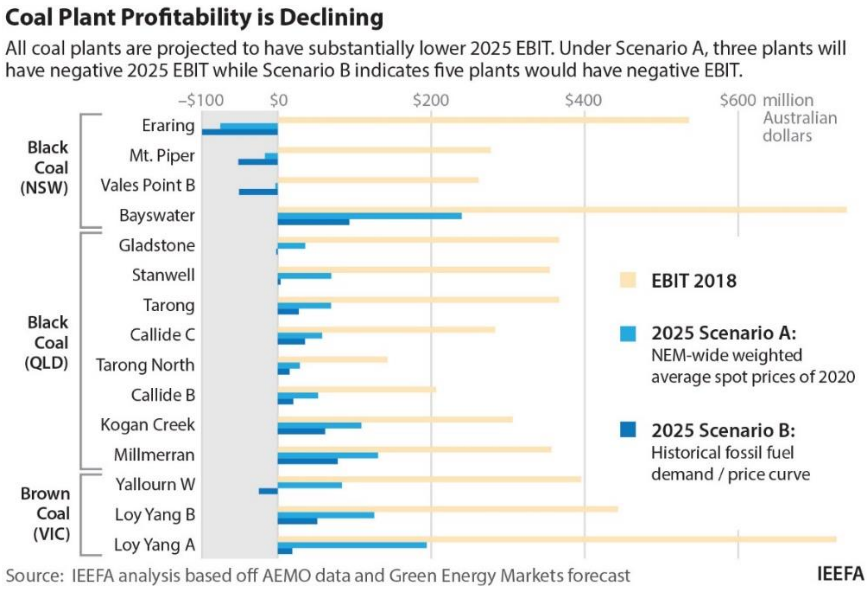
Chapter 2 - Resource Adequacy Mechanisms (RAMs)

IEEFA Perspective on RAMs

Do we have a resource adequacy issue in the NEM or might we have one in future?

The increasing amounts of renewables installed in the system is making coal generators increasingly unprofitable. A recent IEEFA study identified that with all planned renewable projects taken into account, coal generation as a whole will reduce by 28% (from 2019 to 2025) and that 3-5 coal generators in the NEM will be unprofitable by 2025. Profitability was based on Earnings Before Interest and Taxes (EBIT) estimations in the case that generators are, theoretically, fully spot market exposed (i.e., does not include contracts) and excludes revenue from other services such as Frequency Control Ancillary Services (FCAS). Liddell was assumed to exit in 2023.[5]

Figure 2: Earnings Before Interest and Taxes of Coal Plants 2018 vs 2025 ($AUDm)



[5] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.

With these kind of EBIT forecasts, it is clear that coal generator exits are likely to occur far sooner than AEMO has planned for in its Integrated System Plan (ISP).

Once a coal generator exits the market, the profitability of generators outlined above will change. Prices are likely to increase near term and other coal generators that remain online may benefit from increased revenue.

The likelihood of earlier than expected coal generator closure has also been acknowledged by ESB Chair Dr Kerry Schott who stated that additions of renewable supply are moving at rates far higher than previously anticipated.[6] According to Schott, this would likely mean coal plants "will go broke" and close 4-5 years earlier than expected, such that by the mid-2030s Mt Piper could be the sole coal-fired power plant still operating in New South Wales. Interestingly, Schott indicated this was under the conditions of AEMO's Step Change Scenario (intended to be a rapid decarbonisation scenario)[7] which saw wind and solar at around 35%[8] of the generation mix by 2024-25. Yet our analysis suggests wind and solar will be closer to 40-50% penetration by 2025.[9] Therefore, coal closures could unfold faster than even predicted by the ESB.

Multiple factors could cause accelerated and unplanned coal closure/s.

- Firstly, catastrophic plant failure could lead to an accelerated and unplanned coal closure. Legislating mandated 42-month notice periods for coal plant closures ignores the obvious points of the 2017 Muja AB[10] West Australia and 2021 Callide C[11] Queensland situations: catastrophic plant failures are inevitable when they rely on highly centralised but aging generation equipment.

- Secondly, ongoing solar deflation is likely to continue to erode thermal generator profitability to the point of unviability. Solar costs again halving within the next 5 years is an entirely foreseeable outcome, as outlined by Dr Martin Green at the Smart Energy Conference in May 2021.[12]

- Thirdly, global finance will continue to move to avoid stranded fossil fuel asset risks[13] as the world addresses the climate crisis, a factor which could shift the closure dates of coal generators to be much earlier than originally planned. At present, there is no obvious Australian government climate policy considerations, despite the growing global accord for an accelerated

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[6] AFR. Coal power stations going broke: Schott. 16 February 2021.
[7] AFR. Coal power stations going broke: Schott. 16 February 2021.
[8] AEMO. AEMO ISP 2020 – Step Change (DP1). Tab: Summary_2. 5 July 2020. Note that the scenario and modelling Schott was referring to is unclear: Schott referred to "step change" therefore it is assumed this means the AEMO ISP 2020 step change scenario under DP1.
[9] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.
[10] The West. Taxpayers left with big bill as power plant closes. 5 May 2017.
[11] ABC. Queensland blackout to be investigated after fire at Callide Power Station cuts power to large parts of the state. 26 May 2021.
[12] Martin Green. Smart Energy Conference 2021: Solar Cost Deflation Presentation. 13 July 2021.
[13] IEEFA. Financial institutions are restricting fossil fuel funding.

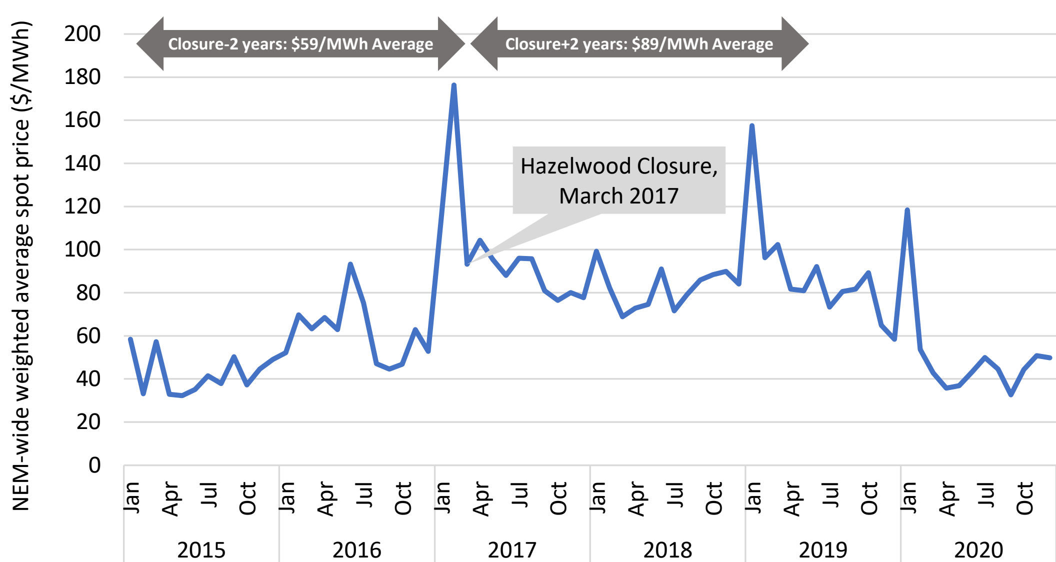
fossil fuel phase-out (outlined in May 2021 in the IEA's Net Zero Emissions roadmap to 2050[14]). However, corporates may act sooner to reduce their exposure to stranded asset risk. As a result, the NEM might have a resource adequacy issue into the future due to the unexpected exit of coal generators.

Origin Energy CEO Frank Calabria said recently,

"This is where the transition has the potential to get messy, as we are likely to see coal-fired generation leaving the market in a planned and potentially unplanned way, leading to shocks to either reliability or affordability. These are clearly outcomes we all want to avoid."[15]

As shown by the sudden unplanned exit of Northern and Hazelwood Coal Power Stations, if a major coal generator shuts with little forewarning it has the potential to lead to significant price spikes. The NEM-wide weighted average spot price 2 years prior to closure of Hazelwood was $59/megawatt hour (MWh). After closure the price increased dramatically, with a 2-year post closure average spot price of $89/MWh (evidenced by Figure 3). Wholesale prices later evened out and recently have plunged, demonstrating that a few years after an unexpected coal generator closure, the wholesale spot price can reduce down to lower levels thanks to low-cost renewable energy. Prices in upcoming years are likely to follow a "saw-tooth" profile as more renewables come online, reducing prices. Then a coal generator closes which temporarily increases prices and stimulates new investment.

Figure 3: NEM-wide Weighted Average Price, By Month, Including Hazelwood Closure Highlight in March 2017



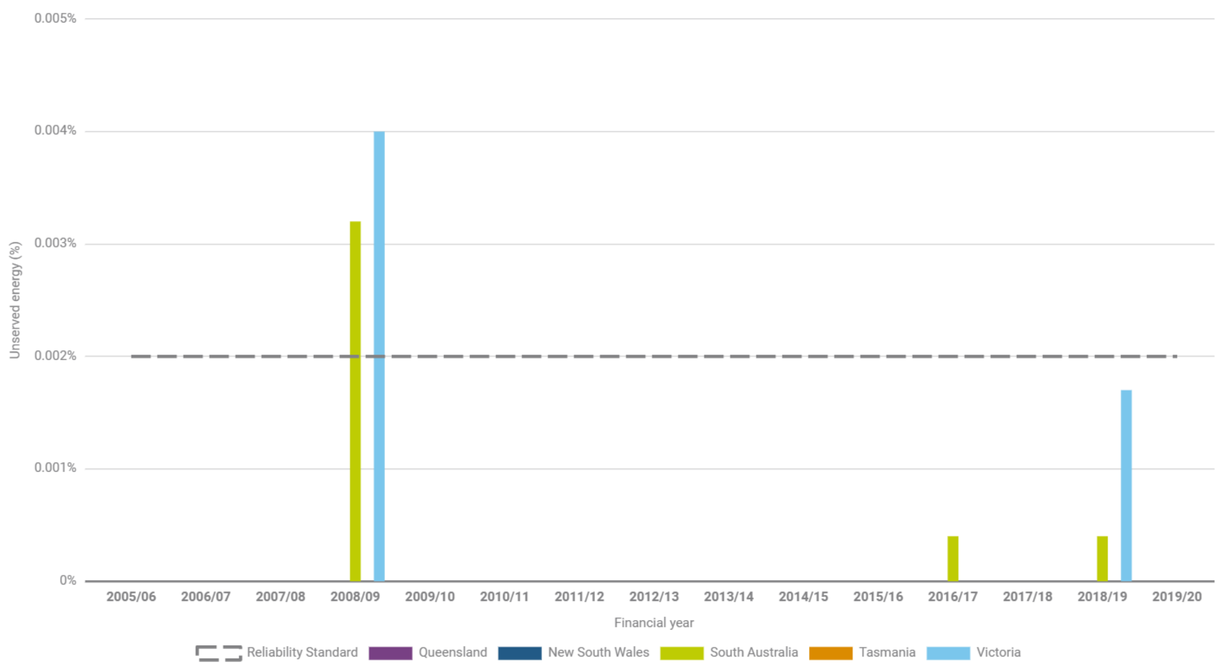
Source: IEEFA analysis. Based on AEMO generation and price data.

[14] IEA. Net Zero by 2050: A Roadmap for the Global Energy Sector. May 2021.
[15] Gold Coast Bulletin. Origin CEO Frank Calabria warns on 'messy' coal exit. 1 June 2021.

A major unplanned and unexpected closure does pose risks to reliability. It depends on if there is enough replacement capacity to fill the gap left by the exiting coal generator.

Reliability standards in NEM states have been met in recent years even with multiple coal generator closures (except for 2008-09 when extreme temperatures in Victoria and South Australia reduced the availability of the interconnector, and Victorian generators contributed to 0.004% and 0.0032% unserved energy respectively).[16] Most recently in 2019/20, according to AEMC, there were "no reliability events (i.e. actual LOR3 conditions) where supply was interrupted due to shortfall of available capacity reserves in 2019/20."[17]

Figure 17: Unserved Energy in the NEM



Source: AEMC.[18]

According to unserved energy figures, the NEM does not historically or currently have an issue with resource adequacy. There is much work being undertaken that would prevent future resource adequacy issues including jurisdictional investment schemes, the introduction of the wholesale demand response (with a particularly significant opportunity from demand response management (DRM) for aluminium smelter refineries), announcements of new battery projects, huge amounts of new renewables being installed, interstate grid interconnectivity expansions, etc. Contingent scenario planning and AEMO's existing processes will also demonstrate if there is a resource adequacy issue, and the potential size of that issue.

[16] AEMC. Information Paper – The Reliability Standard. March 2020.
[17] AEMC. Annual Market Performance Update January – June 2020. 17 December 2020.
[18] AEMC. Unserved energy in the NEM. 2021.

However even with all these processes and mechanisms in place, it is questionable how the retirement of coal generators will be managed given that they are quickly becoming unprofitable.

The electricity industry needs to plan for the orderly and likely accelerated exit of coal generators and the orderly entry of the right amount of replacement capacity. Forecasts of renewable installations in the NEM have been historically underestimated and coal generators are going broke faster than expected. If there is one or multiple unplanned coal generator closure, there will be a resource adequacy issue if the right replacement capacity is *not* yet in place.

The current schedule of closures, taken from recent announcements and AEMO's ISP[19], is that:

- Liddell in NSW is closing in 2023
- Yallourn in Victoria is closing in 2028
- Callide B in Queensland is closing in 2028
- Vales Point B in NSW is closing in 2029, and
- the remaining NEM coal plants are closing in the 2030s and 2040s.

A notable point about this schedule is that 3 coal plants are already slated to be closed over a 2-year period in 2028-2029, demonstrating the ad-hoc nature of the current closure arrangements. The schedule is mainly based on 50-year-end of life and individual generators' commitments (e.g. Yallourn 2028 closure), which presumably are made primarily based on commercial considerations.

IEEFA has predicted another closure is likely by 2025 (additional to Liddell in 2023), because by then, 3-5 coal plants will have negative EBIT.[20] As such, there is still likely to be an additional 'surprise' coal plant closure announcement yet to come in the near term. Indeed, many commentators were expecting a Yallourn closure earlier than 2028 and some still expect a further refinement of Yallourn's closure date.

This is not just short term problem. There are 16 coal plants left in the NEM, all expected by AEMO to retire as they reach end of life in the time period between 2023 to 2048. Some coal plants will likely retire earlier than expected if current market trends continue.

The NEM may have a resource adequacy issue if the coal closure schedule is unplanned.

[19] AEMO. 2020 Integrated System Plan. July 2020.
[20] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.

Why the current notice of closure mechanism is insufficient

At present, there is a requirement on generators to provide 42 months' notice of closure. Exemptions can be granted for a range of reasons and while there are civil penalties for non-compliance[21], even this might *not* provide a sufficient incentive for owners to comply.[22]

Furthermore, 42 months' notice of closure might still *not* be sufficient to prevent resource adequacy issues – for example, in the event that 4 coal generators in one state provide notice they will close in 42 months' time, or in the event that a catastrophic plant closure occurs.

Replacement capacity takes some time to be built and transmission lines alone can take 7 years to construct even after passing a regulatory investment test (RIT-T). The RIT-T itself averages 1.5 years.[23]

How can we solve the problem?

Unplanned closures carry a risk of price spikes, lower reliability of electricity supply, and shocks to local communities. The recent NSW Intergenerational Report stated that energy generation in NSW will mostly be sourced from renewable energy by 2040 and warned that a "slow and disorderly" transition to renewables would result in higher more volatile electricity prices. The report stated that under a "slow and disorderly" scenario, the NSW economy would be 0.9 per cent, or $13 billion, smaller by 2060 compared with a "proactive" energy transition.[24] Workers will be hugely affected, and they need certainty on their futures, as well as a strong and clear transition plan. **An orderly and fast transition is necessary.**

As Mr Perrottet, NSW Treasurer, recently stated:

> *""If you don't know where the future lies, then you can't make adjustments to improve the lives of our people in the future"*[25]

Uncertainty around closure dates of massive, centralised coal plants makes it exceedingly difficult for the private sector to build replacement capacity without knowing how much is needed, in which locations, and at what times.

The NEM therefore needs to have a **long-term plan** to manage both coal plant exits and the timing and location of adequate replacement capacity entry in an orderly fashion that locks-in coal closure dates. This ideally should be federal policy as coal plant closures are a NEM-wide challenge, and if states go it alone there is a risk that a far from optimal closure schedule for the NEM results.

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[21] AEMC. Generator three year notice of closure. 2018.
[22] Operators could decide civil penalties are a 'lesser evil' when weighed against the cost of returning a plant to operation (Blueprint Institute).
[23] Blueprint Institute. Phasing down gracefully. 2021
[24] Sydney Morning Herald. NSW coal industry would die in 20 years, worst-case scenario predicts. 8 June 2021.
[25] Illawarra Mercury. Climate change poses a fiscal risk: report. June 7, 2021.

An orderly transition necessitates that coal closures be announced and locked-in well in advance with a legally enforceable framework of incentives and penalties that removes the uncertainty and risk around early closure. This should involve a progressive plant exit schedule with staggered unit level retirement, giving the private sector time to invest in and build replacement plants in advance of closure. It would go hand-in-hand with transmission and distribution network planning while helping to ensure that investments are made in the right locations in the grid.

Which mechanisms are unhelpful?

An orderly closure schedule is needed. This cannot be done through a mechanism like the enhanced financial retailer reliability obligation (RRO) or the physical RRO as they will keep coal generators online for longer but will do nothing to assist with certainty around closure dates.

The RRO is complex, unproven, not transparent, costly to implement, is not supported by stakeholders, and is unlikely to deliver investment in new dispatchable capacity.

As stated by the ESB in its April 2021 options paper, "the purpose of a physical RRO option would be to provide supplementary investment signals to increase certainty of resource adequacy". The RRO does *not* do this (at anything like least cost to consumers) as it does *not* provide certainty around coal generator closure dates; it only kicks the can down the road to deal with the problem later.

During the ESB's September 2020 consultation round, multiple stakeholders expressed concern about the RRO, suggesting that as a new mechanism (introduced mid-2019), it needs to be experienced and the implications understood before any adjustments are made. The RRO was also noted by stakeholders to be "complex" and "unproven as a means of delivering timely new investment".

Which mechanisms are helpful?

Resource adequacy issues would be best managed *directly* by out-of-market backstop contractual arrangements between AEMO and generators / demand response providers through the Reliability and Emergency Reserve Trader (RERT). This mechanism specifically targets the problem at hand, which is a *possible* resource adequacy issue at some point in the future due to unexpected coal generator closure. If any energy supply gap emerges, a competitive process to fill that gap could be planned in advance and facilitated by AEMO. The RERT could be expanded to include more demand response providers that are *not* covered in the new wholesale demand response mechanism (potentially including households), getting more demand response providers into operation and stimulating the demand response market. The RERT should be used as a backstop mechanism only to prevent market distortion. Wholesale price signals and jurisdictional investment schemes could do the heavy lifting to incentivise investment in new generation.

The RERT should continue to be used, and if in the future the off-market mechanisms were *not* able to keep reliability/security/price at appropriate levels, then an operating reserve could be investigated. At present, there does not appear to be a need for the operating reserve from the AEMC modelling.[26] The ESB / AEMO / AEMC must prove that it is necessary, and that the benefits outweigh the costs before creating this new mechanism.

The ESB could also explore the potential use of the Market Liquidity Obligation (MLO) - separated completely from the RRO - to provide more certainty around energy price and supply into the future. This could involve having the MLO triggered in certain situations (completely apart from the RRO), requiring certain generators and certain energy users / retailers to enter into longer term electricity future contracts (e.g. 3-5 years). It could only be applied to generators of a significant size, such that large generators are covered and would reveal the price at which they are happy to generate into the future. This would result in more transparency around future price and supply and would likely incentivise investment in new capacity. For example, if future prices were very high, retailers / energy users may enter into a contract with a new generator which could help them meet their MLO obligation at a lower cost.

The rest of the heavy lifting to incentivise investment in new generation and firming capacity should be done through the wholesale electricity spot market and the existing jurisdictional underwriting schemes, and ideally also through a legally binding framework to lock-in closure dates of coal generators.

Jurisdictional underwriting schemes, exemplified through the NSW Government Electricity Infrastructure Roadmap, are an effective means to make sure there is enough replacement capacity to fill any gap left by exiting coal generators. It is noted that these may act to further reduce prices in the wholesale market in the medium term, but once more coal generator closures occur, prices will likely rise again. A NEM-wide consistent approach to jurisdictional underwriting could help the whole system align on the best way to build replacement capacity while indicative market pricing suggests ongoing real deflation in wholesale electricity prices (even against current record real lows).

Some options suggested by the ESB would be helpful in managing the risks associated with coal generator closures. These include increased information sharing around mothballing and seasonal shutdowns, and expanding notice of closure requirements to include mothballing, contingent scenario planning, monitoring of reliability and overall costs, and system and market impact assessment processes. However, IEEFA notes that while these would be helpful with mitigating price/reliability risks, none of these policies will mitigate the risks substantially as *none will provide certainty around coal closure dates*.

IEEFA believes the clearest policy is one which locks-in closure dates of coal generators well in advance, through a legally binding framework with incentives for closure. This could be done through, for example, mechanisms proposed by Australian National University (ANU) Professor Frank Jotzo or the Blueprint Institute:

[26] AEMC/ESB. ESB Post 2025. Deep Dive Workshop: Operating Reserves. 22 April 2021.

- **Frank Jotzo's Regulated Closure Mechanism**: "Plants bid competitively over the payment they require for closure, the regulator chooses the most cost effective bid, and payment for closure is made by the remaining power stations in proportion to their carbon dioxide emissions."[27]

- **Blueprint Institute's Coal Phasedown Mechanism**: "Announce sectoral emissions targets for 2026, 2028, and beyond 2030. Offer contracts across the three timeframes for emissions summing to the targets. Implement a sealed-bid auction system for allocating the contracts. Impose mutual obligations to affected workers upon expiry of the contracts. Accommodate a government funding allocation (positive, zero, or negative)."[28]

Through using one such mechanism or another of a similar vein, governments and the private sector would know exactly which coal generators would be retiring and when, and therefore what capacity needs to be built. Price and reliability would be maintained, and planning would be simplified.

IEEFA recommends that the coal closure policy be designed to enable coal generators to close earlier than originally planned in the schedule, as long as there is enough replacement capacity built such that reliability of 0.002% USE is likely to be maintained. The incentives/penalties of the policy could be designed as such. This could enable closures to occur sooner than scheduled, in a manner which would ensure resource adequacy and help Australia reduce emissions. It would prevent a situation in which the NEM has many, emissions intensive, unrequired coal generators remaining in operation unnecessarily.

A **regulated coal generator closure schedule** could complement jurisdictional underwriting schemes by providing jurisdictions with clear information on the capacity that is retiring and therefore the capacity that needs to be built to replace it. It would prevent the states going it alone and potentially arriving at a sub-optimal outcome for the NEM as a whole. It would complement the RERT, and it is likely the RERT would be needed less because the certainty around exits of generators would allow the sector to build replacement capacity in advance.

As Committee for Economic Development of Australia (CEDA) Chief Economist, Jarrad Ball recently stated:

> *"Bold new policy ideas to address the state's ageing population, climate change, geopolitical tensions and the uptake of technology are now critical."*[29]

[27] Frank Jotzo, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[28] Blueprint Institute. Phasing down gracefully. 2021
[29] Illawarra Mercury. Climate change poses a fiscal risk: report. June 7, 2021.

What is the last resort in the absence of a coal closure mechanism?

IEEFA's preferred mechanism is a regulated/incentivised framework to lock-in closure dates of coal generators, rather than an orderly exit management contract (OEMC).

However, if no regulated/incentivised framework to lock-in closure dates of coal generators is introduced, as a *very last resort,* an OEMC could be entered into by state governments with coal generators to keep them online at lower utilisation rates until a point in time where there are no longer any risks to reliability/price.

IEEFA recommends that certain conditions be placed on the OEMC including minimising the cost to consumers and allowing a coal generator to close early if there is enough capacity to replace them. An OEMC should only be entered into if there is a high likelihood that the reliability standard of 0.002% Unserved Energy (USE) would *not* be met.

The OEMC should only be used as a last resort as it represents a government intervention in the market. It will also prevent scarcity pricing, therefore, wholesale price signals will be less likely to stimulate new investment in generators and batteries.

If we plan coal exits to keep prices at the lowest point while maintaining extremely high reliability, investment in new low emissions technology may be slow. For this reason, IEEFA believes the OEMC should only be used as an absolute last resort, and only in the case that a legally binding framework to lock-in closure dates of coal generators has yet to be developed.

Answers to Consultation Questions on RAMs

1. **What types of information provision regarding jurisdictional investment schemes would benefit participants the most?**

Market participants would benefit from having more certainty around the amount of coal-fired power capacity to be retired, and on what date. This requires a more certain timeline that the current 42-month notice of closure requirement which does *not* include any strong financial or legal obligation for generators to comply with, nor does it address the advent of a catastrophic failure event, a clear 'known unknown'.

A legally binding timeline on staggered unit-by-unit closures would provide improved certainty around closure dates, enabling the private sector to confidently invest in the replacement capacity required to fill any gaps left by progressively exiting coal generators.

Market participants would benefit from being provided with information regarding the amount of capacity to be installed/retired, at which location, and at which estimated date. A clear 'capacity in + capacity out' schedule is needed. This would enable jurisdictions, through their investment schemes, to build the right amount of replacement capacity, in the right locations, at the right time.

2. **Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?**

Regarding the agreed national principles for contract design principles, IEEFA agrees that participants should be incentivised to make operational decisions based on wholesale price signals whilst also being increasingly cognisant of the global trend towards accelerated decarbonisation currently impacting the availability of finance and impacting shareholder pressures on Australian corporations.

3. **Are there financial principles missing, or that have been included but shouldn't be?**

Regarding the agreed national principles for contract design, a key principle missing is that climate and environmental risks should be quantified and considered in all decisions, and the shrinking availability of finance for high emission assets should be considered.

4. **What are some of the market-based signal challenges, if any, with mothballing/seasonal shutdown?**

Market-based signal challenges with mothballing/seasonal shutdowns do exist. If a generator is mothballed/seasonally shutdown and then turns back on, there will be fluctuating supply and it may be harder for AEMO and other market participants to plan their operational regimes. Furthermore, mothballing/seasonal shutdown could be costly and could slow down the development of new capacity as it may confuse the signals for new investment (if prices increase, mothballed generators may turn back on, reducing price and therefore dampening signals for capacity investment).

However, there are some cases where mothballing/seasonal shutdown could be useful for generators and consumers by improving price and/or reliability in the NEM. In South Australia, the last remaining coal generator, Northern Power Station operated for some years in winter and not in summer before it shut down because it could no longer cover its costs.[30] Mothballing/seasonal shutdown arrangements should therefore be carefully planned to maximise consumer benefits and minimise risk.

5. **What additional costs or process burden may the disclosure of such information place on stakeholders?**

Stakeholders should be required to disclose information on mothballing/seasonal shutdown as it is a key data point needed by energy planners. It is reasonable that any associated compliance costs or process burdens are borne by the participant, especially as these are likely to be small.

6. **What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?**

[30] Global Energy Monitor. Northern Augusta Power Station.

Stakeholders should be required to disclose information on mothballing/seasonal shutdown as it is a key data point needed by energy planners. This could easily be gathered through AEMO's existing Generator Information Survey process and the MT PASA. Furthermore, shareholders should be privy to this information because, as set out in the ASX listing rules, the Corporations Act and the ASIC Act, public companies must immediately disclose any material information that could affect the price or value of their shares.[31]

7. **Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?**

No, disclosure is different to operation. The participant may still operate flexibly within reasonable bounds.

For significant capacity withdrawals, the participant should be required to publicly notify the market as other commercial participants need to plan their own market participation strategy. Furthermore, shareholders have a right to know this information and AEMO and regulators need to plan to ensure reliability, security, etc. The information on mothballing/seasonal shutdown could be provided through a more detailed data gathering process in AEMO's Generation Information Survey or through the Medium Term Projected Assessment of System Adequacy (MTPASA) process as outlined by the ESB.

8. **Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?**

Yes, the exemption process should be extended to include mothballed generation.

Mothballing/seasonal shutdown information sharing requirements, and exemptions from this, should only apply to large generators above a certain megawatt size, reflective of global pressure to accelerate closure of high emission generation capacity, noting as well that smaller generators' withdrawal of capacity should *not* have such a major impact on the market and would therefore be likely to have a higher compliance/process cost than associated reliability/security benefit.

9. **What suggestion do stakeholders have for defining mothballing**

No comment.

10. **How can governments, market bodies and market participants better work together to be prepared for exits?**

The future lifespan of existing 'approaching end of technical life' high emission coal generators is one of the greatest elements of uncertainty affecting the Australian electricity market, with potentially profound impacts for commercial returns on

[31] The Conversation. Explainer: what exactly must companies disclose to investors? 24 August 2017.

investments as witnessed by the 55% decline in AGL Energy's share price over the last 5 years. Further, uncertainty over exit timelines is an extra financial risk undermining ahead-of-time deployment of new firming capacity.

While AEMO publishes a schedule for expected closures of coal-fired power plants, the reality is that these are far from set in stone. The global track record of the last 5 years is that closures are happening well ahead of previous expectations, reflecting the growing confluence of commercial, technology, climate and policy pressures. Replacement capacity needs to be built, but no one knows when, where, or how much because there is no certainty on when each coal generator will be closing. AEMO's ISP has provided much needed planning capacity but the speed of the energy transition has exceeded even the most aggressive ISP scenario, in large part reflective of the Federal government's climate science denialism and unwillingness to comply with climate treaty obligations.

So far, the common way to install replacement capacity has been for governments to underwrite or directly fund new power generation capacity. To date, most state governments have focussed on running periodic competitive open tenders but without any explicit consideration or criteria about how the projects contracted could effectively cover for the exit of coal generators over time.

The Federal government has been more focussed on the issue of providing capacity that is dispatchable, while its processes for selecting and funding projects are opaque, reactionary, and uniformed by the growing global response to climate science. There is no clear coherent strategy evident that is tied to overarching quantitative objectives to ensure timely replacement of coal plants and/or reduced emissions.

This lack of clear strategic direction and what appears to be a random and disjointed process for selecting and funding projects has meant the Federal government has *not* fostered and harnessed the benefits of competition. This is perhaps best illustrated by the decision to approve Snowy Hydro to spend up to $10 billion on its 2,000MW pumped hydro expansion[32] without an open competitive process to consider and evaluate potential alternatives and the grid reliability advantages of stronger geographic dispersion.

The lack of a Federal plan means that individual states have stepped forward with individually sensible plans to ensure new capacity is being built that can replace exiting coal on a timely basis while also reducing emissions. This however is far from optimal as it ignores the system-wide benefits of a nationally coordinated approach.

The NSW Electricity Infrastructure Roadmap has established a framework built on competitive selection processes that appear to be open to wide number of participants. Similar models could be used in other jurisdictions to great effect. However, even this type of policy does *not* provide certainty around closure dates

[32] IEEFA. Snowy Hydro's Cash Drain. November 2020.

for coal generators, therefore the price/reliability risk associated with unexpected closure remains.

The jurisdictional underwriting schemes would benefit from a consistent NEM-wide approach to underwriting and a legally binding framework locking-in coal closure dates.

The factor that most clouds the timing around coal plant closures is the lack of a regulatory framework for emissions reduction that investors see as likely to hold over the next decade or two. If there was an unambiguous and legally binding timeframe for emission reductions, private sector investors would be more willing to invest in new generation capacity aimed at replacing coal capacity, in advance of certainty about their closure dates. This is because they would know that even if they made an investment in replacement capacity too early, it would not be long before a coal closure occurred, and the investment paid off. This would also help better guide regulators and transmission system planners on the need for investment in new transmission capacity to support connection of replacement capacity and energy.

Unfortunately, a legally binding emissions reduction framework does *not* exist and repeated attempts at introducing one have proven politically difficult. While IEEFA's analysis[33] suggests coal plant closures may be closer than expected, it will take a brave investor to build a plant over the next few years in advance of a firm closure commitment given the degree of oversupply and depressed prices forecast.

In the absence of a legally binding overarching emissions reductions framework, a **regulated/incentivised coal generator closure framework** could be implemented. This would lock-in the dates that coal plants will close and include incentives for owners to honour these dates by keeping plants operational up until the date of closure or until sufficient replacement capacity is in place. Such an idea has been put forward by ANU Professor Frank Jotzo who proposed an auction process that would provide a reward to plants that agreed to shut on a certain schedule ahead of other coal power plants.[34]

> *"Plants bid competitively over the payment they require for closure, the regulator chooses the most cost effective bid, and payment for closure is made by the remaining power stations in proportion to their carbon dioxide emissions."*[35]

With dates publicly known and certain, private sector investors could then make investment decisions about building new supply with far greater confidence. Jotzo's proposal is extremely useful for avoiding potential disruption from unanticipated coal exits because it puts in place a legally enforceable and public schedule.

[33] IEEFA. Fast Erosion of Coal Plant Profits in the NEM. February 2021.
[34] Frank Jotzo, ANU. Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations. November 2015.
[35] Ibid.

The Blueprint Institute has also suggested a Coal Phasedown Mechanism (CPM) to facilitate a phased reduction of emissions from coal generators. The mechanism works by setting sectoral emissions targets, offering contracts for emissions summing to the targets, implementing a sealed-bid auction system to allocate contracts for emissions, redeploying/ retraining/ remunerating the affected workforce, and allocating government funding towards the phase-down mechanism.[36]

11. Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?

We support the ESB to introduce a regulated framework to lock-in coal closure dates. However, in the absence of this, an OEMC could be used as an *absolute last resort*. State governments are best placed to enter into an OEMC with a respective participant in the event of an early exit.

If an OEMC is entered into, it should include the following conditions:

- The OEMC would only need to be used if there was no legally enforceable framework locking-in coal closure dates.
- Ideally RERT arrangements are used to contract with energy resources to maintain reliability. If this is not possible, then an OEMC could be used as last resort.
- Costs of the OEMC scheme should go through the respective state Treasury and *not* be charged directly to consumers. Charging the OEMC costs to Distribution Use of Service (DUoS) would mean consumers bear the cost of any poor design in the OEMC contract, and there would be reduced transparency of the process.
- Any OEMC payments to exiting coal generators should only be made once the generator is under administration.
- OEMC payments should be determined through a method which minimises the cost of the scheme so that overpayment for exits does not occur.
- The OEMC contract should only include the required capacity/generation that is needed to maintain reliability. For example, the state government contracts for 10% of the output of a generator, as the energy supply gap is as large as 10% of the generator's output. The exiting generator is able to have the required capacity available when needed to ensure reliability, however, does not need to generate at that capacity at all times.
- The OEMC should enable the coal generator to close earlier than expected if there is enough replacement capacity built such that reliability is likely to be maintained within the standard of 0.002% Unserved Energy (USE).

[36] Blueprint Institute. Phasing Down Gracefully. 21 December 2020.

- While under an OEMC contract, the generator should bid their output into the wholesale electricity spot market at their short run marginal cost in order to prevent market distortions.

- An OEMC should only be entered into if there is a high likelihood that the reliability standard of 0.002% USE would *not* be met.

12. Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?

Yes, any OEMC or other contract with coal generators in the event of an early exit should be kept separate from the RERT. The RERT could be expanded to include more demand response providers.

13. Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?

The measures of success do *not* include any mention of emissions. A key measure of success should be supporting the state government's emissions reduction targets.

14. Are there any obvious priorities given current and plausible likely future market scenarios?

Coal generator exits are likely to occur far sooner than AEMO has planned for, as explained above. These exits need to be planned for and managed. Contingency scenario planning is a helpful tool for this. The scenario analysis results should be made available to the public.

15. What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?

The existing RERT should be used and potentially enhanced rather than developing a physical RRO or enhanced financial RRO. Reasoning is detailed further below.

16. Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?

17. [Financial RRO option] How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?

18. [Financial RRO option] What are options to make the RRO simpler, while still advancing some measures of success?

19. [Financial RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?

20. [Physical RRO option] Should it be a triggered mechanism, or be developed as a rolling one?

21. **[Physical RRO option] How should the physical certificates be regulated?**

22. **[Physical RRO option] How would a physical RRO impact contract market liquidity?**

23. **[Physical RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?**

Answers for Q 16 – Q 23:

The RRO will likely keep coal-fired power plants generating for longer. It does *not* reduce uncertainty; it just delays the inevitable coal plant closure. It is *not* transparent. It will increase bills for electricity consumers, potentially significantly, as well as cool investment in new capacity.

Efforts to keep inflexible coal plants afloat, like the enhanced RRO, are counter-productive in terms of both energy affordability and reliability as well as being contrary to both Federal and state government's commitments to address climate risk. Rather than seeking to delay or even deny the inevitable exit of coal, the ESB must plan to replace them.

We do *not* support the physical RRO or financial (enhanced) RRO as it has the following issues:

- It will be costly to implement (acknowledged by the ESB).
- It will be complex to administer.
- It will have low transparency.
- It is anti-competitive as it favours dispatchable generators.
- It has a risk of overcompensating coal-fired power stations, providing additional revenue to these generators and keeping them online past their economic life, thereby increasing uncertainty regarding when coal generators will close.
- It will provide additional revenue to emissions-intensive generators, therefore Australia and the NEM states will be at risk of *not* meeting climate and/or renewable energy targets.
- It is inconsistent with the recent IEA report that states that to reach net zero globally by 2050, "the least efficient coal plants are phased out by 2030" and advanced economics decarbonise their electricity sector by 2035.[37]

The physical or financial (enhanced) RRO is said to be solving the problem of incentivising new dispatchable plants**.** However, this is not an efficient way to do

[37] IEA. Net Zero by 2050: A Roadmap for the Global Energy Sector. May 2021.

that. Incentives for new dispatchable plants should be more direct and targeted at new low emissions plants (e.g. through jurisdictional investment schemes like the example from NSW), and not at every dispatchable plant in the existing NEM.

The physical or financial (enhanced) RRO is said to be solving the problem of preventing unexpected coal generator closures. It will *not* do this but rather, it will kick the can down the road, providing additional revenue to coal generators to keep them online for longer, and will not provide certainty around closure dates.

There is no modelling or information released which provides a case for the enhanced financial RRO or physical RRO. The ESB, nor any other body, cannot argue that the benefits of this policy outweigh the costs. IEEFA does *not* support either RRO option. However, in the worst case scenario, a financial RRO is preferred to a physical RRO.

IEEFA has reviewed responses regarding the RRO from submissions to the ESB's September 2020 consultation.[38] Most stakeholders were opposed to the RRO proposal and/or the creation of a decentralised capacity market. Key concerns raised by stakeholders included:

- Regarding the enhanced RRO:
    - It is not yet proven, and needs to be experienced and with the implications understood,
    - It may produce unanticipated costs and risks,
    - Any modification of the RRO will lead to uncertainty, and
    - Is too indirect and uncertain, and overly complex.
- Regarding a decentralised capacity market:
    - It may increase cost to consumers,
    - It would be disruptive and provide limited price certainty.
    - It needs comprehensive consultation.

[38] Energy Security Board. ESB Post 2025 Market Design Consultation Paper. 7 September 2020

Table 1: Select Comments From Submissions – Enhanced RRO and Decentralised Capacity Market

<table>
<tr><th colspan="6">Submissions to Consultation Paper</th><th>ESB Directions Paper</th></tr>
<tr><th rowspan="2">Initiative</th><th rowspan="2">Description</th><th colspan="3">IEEFA interpretation of positioning in Submission</th><th rowspan="2">Summary of stakeholder comments</th><th rowspan="2">ESB Approach in Directions Paper 5 Jan</th></tr>
<tr><th>Not supportive</th><th>Neutral / further analysis needed</th><th>Broadly supportive</th></tr>
<tr><td>Enhanced RRO</td><td>The Retailer Reliability Obligation (RRO) is an existing NEM mechanism to incentivise liable entities (retailers and large energy users) to enter a contract to supply their share of expected peak demand, when there is a forecast supply shortfall in NEM regions/time intervals. The RRO has been recently introduced and has been triggered only in South Australia. ESB proposes to “expand/enhance” the RRO through various potential mechanisms</td><td>- UNSW CEEM
- AGL
- CS Energy
- Grattan Institute
- The Australia Institute
- Origin Energy
- IEEFA</td><td></td><td></td><td>- RRO is not yet proven, needs to be experienced and implications understood
- may produce unanticipated costs and risks
- modification of RRO will lead to uncertainty
- RRO is too indirect and uncertain, overly complex</td><td>ESB will continue to explore RRO enhancement and “As part of this, the ESB will reflect on how to address concerns raised by stakeholders regarding the complexity of the Retailer Reliability Obligation (RRO), effectiveness at driving investment, and imposing a high compliance burden.”</td></tr>
<tr><td>Decentralised capacity market</td><td>The decentralised capacity market is another option to prevent supply shortfall. It places obligations on retailers to procure capacity. The capacity could be defined in financial or physical terms. The retailers themselves can define how they will meet the reliability obligations.</td><td>- CS Energy (unlikely to incentivise investment)
- Origin Energy</td><td>- Grattan Institute
- ARENA (may increase cost to consumers)</td><td>- Alinta Energy (prefer to include trading mechanism. But does not support RRO)</td><td>- May increase cost to consumers
- would be disruptive and provide limited price certainty
- Need comprehensive consultation</td><td>“The ESB will not consider a decentralised capacity market as a separate competing option but will consider the physical backing required of qualifying contracts as one possible enhancement to the RRO. This approach will ensure possible future reforms are made within the RRO”</td></tr>
</table>

Comments from stakeholders regarding the enhanced RRO (from the September 2020 consultation round) are shown below. It is clear most stakeholders are *not* supportive of the enhanced RRO. IEEFA was therefore surprised to see it once against tabled as an option in the ESB April 2021 paper.

Table 2: Select Comments From Submissions – Enhanced RRO

Respondent & link to submission	IEEFA interpretation of position	Comment quoted from Submission
UNSW CEEM	Not supportive – prefer use of government tenders and auctions to deliver capacity	"**reasons for concern about the likely effectiveness and efficiency of the present RRO arrangements, let alone changes to them.** There are clear opportunities to improve the RRO design, particularly around transparency and mitigation of market power by what is currently a retail electricity market sector that exhibits oligopolistic aspects…. As discussed above, we have **concerns about the current RRO design**, which may limit its useful in a wider role to deliver other mechanisms. **Instead, we would suggest further investigation of the use of government tenders and auctions** which have proven capabilities to deliver low cost generation and storage projects by private partners taking advantage of low risk, government underwritten off-take contracts."
AGL	Not supportive – may produce unanticipated costs and risks	"While it is possible to adjust the RRO to provide longer term signals for capacity, we have **concerns that adjusting the RRO to achieve a different policy objective and ambition will produce unanticipated costs and risks**. Removing the RRO trigger or introducing more stringent obligations regarding the amount and type of qualifying contracts may incentivise greater levels of contracting. However, the complexities involved in retailer hedging means it would be difficult to anticipate cost, impact on investment incentives, and the amount of resource capacity and reliability standard that is being delivered."
Australian Aluminium Council	Keep existing RRO but do not introduce any other RAMs	"In the absence of quantitative analysis being included in the Paper, it is not clear which amongst the Resource Adequacy Mechanisms discussed in the Paper may achieve the best combination of effectiveness, least-cost, and predictability. In general terms the Council prefers mechanisms which would build on existing markets and price signals rather than introducing new markets whose behaviour may be less predictable and less able to be hedged through established risk management products. Given the significant number and scale of announced actions and policies by both State and Federal Government's directed at the issue of resource adequacy, the **Council supports retaining the existing Retailer Reliability Obligation, but is cautious of other resource adequacy mechanisms being introduced."**
CS Energy	Not supportive – modification of RRO will lead to uncertainty	"The options proposed for strengthening long-term investment signals are difficult to assess as key aspects have not been explored. **Modifying the Retailer Reliability Obligation (RRO) will only achieve greater uncertainty in the near-term given its immaturity and the recent changes that have been made to that mechanism.** These options could perhaps be revisited once the efficacy of the current RRO can be assessed. At that time, the options need much greater detail to understand the relative costs and benefits and the overall merit to exploring further. The RRO is already as firm as it can be with much effort expended during the design process on this topic. The RRO design process also highlighted the complexity of establishing and implementing a physical mechanism, which was its original intent. The ESB must also be cognisant of how any changes may affect compliance requirements which may prove prohibitive to smaller retailers." "**Modifying the RRO should not be considered until the mechanism has matured and should leverage the learnings from its design process including the complexities of a physical capacity mechanism."**
Grattan Institute	Not supportive	"The Retailer Reliability Obligation (RRO) was designed to address concerns about resource adequacy. It has yet to be triggered and **doubts exist as to whether it will be an effective solution"**
The Australia Institute	RRO can reduce incentive for new entrants	"Under the RRO, gentailers that have existing synchronous generation assets like high-cost gas peaking plants and may turn on these assets to meet their own requirements or sell the services to other liable entities. This **may lead to sub-optimal outcomes for consumers** as new technologies, new entrants or solutions such as demand response may not be incentivised to enter the market due to the gentailers dominance."
Origin energy	Not supportive – RRO is too indirect and uncertain	**"Decentralised capacity markets like the RRO are <u>too</u> <u>indirect</u> (with the obligation on retailers) and are <u>unproven</u> as a means of delivering timely new investment**. A full decentralised capacity market underpinned by physical contracting requirements would also be disruptive, potentially impeding financial contract market liquidity and necessitating changes to current market settings to reduce the market price cap (MPC)." "Requiring contracts to be physically back could undermine risk management"
IEEFA	Not supportive – overly complex	"The enhanced focus on reliability and capacity procurement of the Retailer Reliability Obligation and decentralised capacity markets look **overly complicated and ineffective**, and are likely to distract from the larger picture and lead to unnecessary network 'gold plating' and/or excess capacity. Although we have not analysed these options in detail, they would seem less efficient than an operating reserve market and clear market price signals."

Comments from stakeholders regarding the decentralised capacity market (from the September 2020 consultation round) are shown below.

Table 3: Select Comments From Submissions – Decentralised Capacity Market

Respondent & link to submission	IEEFA interpretation of position	Comment quoted from Submission
ARENA	May increase cost to consumers	"Decentralised capacity markets, where targets are set for each retailer, may also lead to **retailers retaining 'long positions'** in each trading interval to avoid administrative penalties that, in aggregate, are significantly in excess of the needs of the market, at a **cost to customers."**
CS Energy	Not supportive	"A decentralised capacity mechanism is unlikely to incentivise new investment, with costs likely to be passed through to consumers as capacity charges. Where these mechanisms have been implemented in other markets, their objective has been largely to act as an in-market emergency mechanism on peak days." "**A decentralised mechanism is unlikely to provide long-term investment signals and it is unclear what benefits it would bring additional to the current frameworks."** **"CS Energy cannot support its further development as there are no demonstrable benefits"**
Origin Energy	Not Supportive – it would be disruptive and provide limited price certainty	"In Origin's view, the purported advantages of decentralised procurement frameworks relative to centralised frameworks from a general risk allocation perspective are not evident. Under both approaches over procurement risk is partially shifted from generators to the designated central authority (and consequently consumers), albeit through retailers in the case of decentralised frameworks…. With respect to potential benefits, centralised capacity markets provide the most direct means of ensuring resource adequacy and can be used to facilitate a certain level of reliability over a specified time horizon in line with market requirements and government expectations. This contrasts with decentralised frameworks, where market settings and obligations on retailers are intended to facilitate (but not guarantee) the required level of investment." "**A full decentralised capacity market would be disruptive and provide limited price certainty for consumers or investors"**
Grattan Institute	Supportive of decentralised capacity market in which market participants bear cost of under-procurement or over-procurement, not consumer	"in a 'decentralised' approach, there remains an important choice between a central agency setting future capacity requirements and requiring market participants to procure this capacity, or market participants determining what resources to procure to avoid penalties for contributing to poor reliability. We recommend the latter approach, on the grounds that it better protects consumers from mis-specified reliability requirements." "**In summary, we support a market-determined capacity market** utilising commercial market drivers. But there are risks. The next steps must involve comprehensive stakeholder consultation on design details to avoid unintended consequences and address identified risks."
Alinta Energy	Supportive	"A decentralised capacity market featuring a trading mechanism (as opposed to a compliance obligation) is Alinta Energy's preferred model over the medium term (2025 and beyond). **We do not support any increase in penalties under the Retailer Reliability Obligation nor do we support the permanent removal of the RRO trigger as part of a modified RRO.**"

Chapter 3 - Essential System Services, Scheduling and Ahead Mechanisms

24. What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?

The ESB Options Paper contemplates the introduction of a system security mechanism (SSM) which IEEFA suggests is needed to keep the system functioning in the near to medium term. The alarming rate of increase in AEMO interventions highlights the urgent need to address system security. We strongly encourage the ESB to present a clear and definitive proposal to Ministers with the intention that a market-based solution be established soon. This market mechanism could serve to reduce operator interventions and therefore would avoid additional cost to consumers. This however is only an interim solution.

The range of mechanisms and design features put forward in the ESB Options Paper are primarily focussed on maintaining the functionality of the legacy centralised synchronous generation model. As the energy transition continues, maintaining adequate system security will become even more problematic.

An approach that preserves historical systems and incentivises baseload coal plants to stay in the market to provide operating reserves will act as a drag on the transition. In the long run, it will be cheaper and more efficient to design the near term mechanisms to incentivise Inverter-Based Resources (IBRs), DER and storage, and to move efficiently towards a new operational model while still including coal in new ESS markets and allowing plants to exit as and when market forces dictate.

Setting up new markets for ESS appears necessary in the near term to establish price signals and to keep the system working. However, it is inevitable that traditional synchronous generation will be overtaken by variable renewable energy which will soon change the mechanics of system security. In such a scenario, new markets may quickly become inefficient and sub-optimal.

Up until now, and as indicated in the ESB paper, the approach to mitigating system security issues has been to develop ways to unbundle services that have traditionally been provided by synchronous generators, and to set up markets and mechanisms for remunerating providers of such services either through real-time spot markets or as scheduled (contracted) services. This will *not* lead to an optimal NEM in the long run.

The ESS identified in the ESB paper are aimed at valuing and maintaining the existing synchronous grid functions under the existing synchronous grid physical layout while using the existing synchronous grid market frameworks. The transition to a zero emissions NEM equates to a transition to IBRs and a zero-inertia grid. As this happens, the market mechanisms proposed by the ESB will become obsolete.

As DER and variable renewable energy proliferate, it will be necessary to re-imagine the grid architecture and operational control approach. The current central control and transmission planning may *not* be suitable for the post-transition, majority renewable grid. The ESB Options Paper avoids considering grid requirements for a future zero inertia grid in favour of focussing on near-term solutions to current constraints in the legacy synchronous system.

IEEFA would suggest proposed reforms should be designed to migrate simply and seamlessly over time towards a new framework that enables flexible operation with up to 100% non-synchronous renewable energy.

In the future, the total capacity of synchronous machines will be outweighed by the total capacity of asynchronous inverter-based resources. At that point it may be more efficient to ring-fence any remaining synchronous machines, de-coupling their frequency dependence from the wider NEM, with the aim of operating the NEM with new modern architecture and control methodology. In developing the current reforms, the ESB should consider scenarios for the long-term end-state of the NEM, and then work backwards to ensure that proposed near term reforms and investments do not leave market participants and consumers stranded with a costly old-world grid.

25. **What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?**

We note the benefits of large-scale battery storage for providing ESS and the role batteries have played during recent contingency events, including in response to the turbine failure at Callide B in May 2021. In this case, Tesla reported that the Hornsdale battery responded like a synchronous generator by using a "virtual machine mode".

It would appear that the common thinking around current reforms is to adapt all new technologies to simulate and augment the services provided by synchronous generators, even though they are in decline. In IEEFA's view, a parallel effort should be undertaken to prepare for a future scenario with inverter-based resources as the foundation of the NEM. Grid-forming inverters, new operational control methods and new grid architectures should be prioritised. Reforms could allow for adapting legacy synchronous machines into new grid arrangements in order to ease the transition away from fossil fuel generation. The longer we stick with the legacy synchronous model, the harder it will be to change when that model is no longer viable.

A Transmission Network Service Provider (TNSP)-led solution in the investment timeframe should *not* be constrained by the current proposed reform agenda. The near term operational System Services Mechanism (SSM) should recognise that the transmission and distribution networks may need to be reconfigured in the future to enable a stable network that supports up to 100% inverter-based generation assets. In this case, the operational SSM may have limited complementarity with the investment timeframe. This is concerning, as there is an increasing risk that current reforms will lock in the model of a centrally-controlled synchronous interconnected

AC grid, which is unlikely to be the optimal configuration in a future system dominated by distributed inverter-based resources.

Serious and urgent consideration needs to be given to the best grid configuration for the post-transition NEM.

26. How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?

Operating reserves are not necessary if system services are procured more efficiently through scheduled services, which should increasingly allow for participation by DER and demand response. A market for operating reserves should only be considered in the future if benefits clearly outweigh costs. If designed well, scheduled services could alleviate reliability constraints as well as providing essential system services, while compensating stakeholders appropriately depending on the service provided. The design should ensure efficiency and lowest cost, with a procurement schedule that prioritises fast response zero-emissions reserves ahead of slow-response fossil-fuel reserves. Ramping should be viewed as a secondary matter, as most new capacity is expected to be in the form of inverter-based resources capable of very fast response.

The era of relying on slow-ramping coal and gas plants is over. All new market reforms should prioritise the shift to IBRs, augmented as necessary by hydro, gas, and finally coal, in order to maintain reliability and system security. In due course through appropriate mechanisms, IBRs may supply all required services and as the transition progresses, could open pathways to the next stage of market reform enabling a zero-emission and zero-inertia grid paradigm.

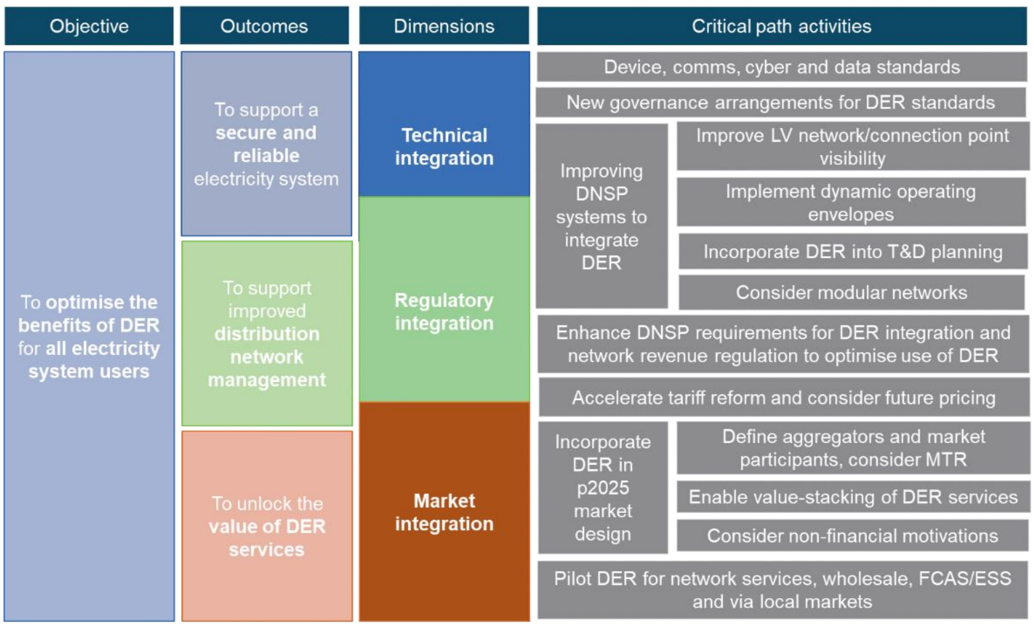
Chapter 4 – Integration of Distributed Energy Resources and Demand Side Participation

The ESB's 2020 DER Roadmap defines priorities for the technical, regulatory and market integration of distributed energy resources (see Figure 1). It sets out the following critical path activities for market integration:

- Acceleration of tariff reform and consideration of future pricing mechanisms
- Incorporation of DER into the Post 2025 Market Design, especially:
    - Streamlining market participant categories in a way that accommodates DER aggregators
    - Considering ways to allow for multiple trading relationship at a customer's site
    - Enabling value-stacking of DER services
    - Considering non-financial motivation of consumers

- Piloting DER for network services, wholesale, FCAS/ESS and via local markets.

Figure 4: ESB DER Integration Roadmap



How does the April 2021 consultation paper deliver on these critical path activities?

In short:

- There is commentary on tariff reform but no clarity on how it will be delivered.
- On market participant categories, there is a proposal for a 'trader services' model but it does not seem to have been progressed very far and there is little clarity on how it will be implemented. In addition, there are two options for 'scheduled light'.
- There are two high level options for multiple trading relationships (MTR).
- There is nothing tangible on value-stacking (just an indication of its desirability).
- There is nothing on the non-financial motivations of consumers, although there is a new ECA-initiated AEMC-proposed risk-based approach to consumer protections.
- Piloting DER in local markets is already happening through ARENA/AEMO/third-party trials in Victoria and the South West Interconnected System (SWIS).

In addition, there is a plan using an IT start-up model metaphor of an 'egg timer' which we believe is inappropriate for the policy work of market design. It is surprising that the ESB is proposing such a plan given the same approach has been used for 9 months with no outcomes in terms of actual changes to better incorporate DER into energy and FCAS markets nor in providing network support services.

Instead of proceeding with the Maturity Plan, IEEFA recommends the ESB prioritise the following urgent reforms:

- Fast-tracking of rule changes on the governance of DER technical standards by AEMC
- Greater resourcing and fast-tracking of DEIP work on Dynamic Operating Envelopes, including the AER taking responsibility for leading this work given the implications for DNSP connection agreements and the potential for improved consumer outcomes, including greater DER availability to participate in network support services
- Putting modular definitions of market participants in place (as below)
- Planning that includes scenarios for operating the NEM with zero inertia[39].

27. **What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could also be considered for different types of consumers?**

28. **Is the unbundling of services delivered by active DER resources (e.g., solar PV, batteries or smart hot water appliances) from energy supplied by DER viewed as important to allow innovation and new business models? What might be the pros and cons of this approach?**

29. **What might be implications of a growing fleet of active batteries or electric vehicles? Are other pathways that need to be considered to reflect these needs?**

30. **Are there constraints on switching providers with DERs today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?**

31. **What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?**

32. **Are there other potential approaches that could be considered?**

[39] IEEFA report. Australia's Opportunity to Plan Ahead for a Secure Zero-Emissions Electricity Grid, March 2021.

Answers for Q 27 – Q 32:

IEEFA see no issues with energy market institutions using a risk assessment tool to understand risks related to DER products and services when considering rule changes or reviews. However, a comprehensive review of the National Energy Consumer Framework (NECF) is required given that it was developed prior to the large scale investment in rooftop solar by Australia households and given the emerging investment in storage (stationary and on wheels), smart appliances and energy management systems, not to mention emerging and future Virtual Power Plants and other means for consumers to participate in markets using their DER.

The NECF is no longer fit-for-purpose because issues of switching providers with DERs are not in scope and the whole issue of separate contracts for provision of DER-related services was *not* considered when the NECF was conceived.

IEEFA recommends the ESB request the AEMC review all energy consumer protections with a view to replacing the NECF.

33. **Under what situations could the distribution network operator perform the role of the retailer / aggregator?**

34. **How might DER assets be managed in a situation where no retailer / aggregator is nominated?**

35. **What are the issues surrounding connection agreements that can facilitate a retailer / aggregator for market participation and the delegation for the enforcement of limits to both DNSPs and AEMO?**

36. **Noting the differences in market arrangements between the WEM and the NEM, are there aspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?**

37. **What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?**

38. **Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?**

39. **Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?**

40. **Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?**

Answers for Q 33 – Q 40:

IEEFA suggests the options proposed are illogical, as detailed below. It is unclear why stationary and mobile batteries (EVs) are *not* included in the ESB's deliberations.

41. What are other options to consider that might deliver better outcomes for consumers?

The consideration and implementation of the ESB's rule change for new governance arrangements for DER technical standards.

Consideration of residential consumers participating in the wholesale demand response mechanism or expanded RERT.

42. Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?

It is unclear why the ESB is seeking feedback on principles relating to the interoperability of DER devices. We are unclear how this will 'guide efforts on the creation of standards' when the ESB itself has lodged a rule change for new governance arrangements for DER technical standards. IEEFA is also unclear as to what is meant by 'structures that incorporate active DER efficiently into the larger system'. Both appear contrary to National Electricity Law and National Electricity Rules which, for example, already grant consumers the ability to share smart meter data with consumer authorised representatives. Are the proposed principles a precursor to rule changes? If not, what is their purpose?

'Network services' need to be investigated through the process to amend network revenue regulation. The COAG Energy Council has requested that the Australian Energy Market Commission (the AEMC or Commission) conduct the economic regulatory framework review to monitor market developments on an annual basis (ENERF), to consider whether the economic regulatory framework for electricity network is sufficiently robust and flexible to continue to support the long term interests of consumers in a future environment of increased decentralised energy supply. Is the ESB proposing to change these review arrangements?

'Dynamic limits' (or dynamic operating envelopes) is a network operation issue, not a market design issue and is also being managed through a Distributed Energy Integration Program (DEIP) work stream. Similarly, 'local energy services' do not exist (unless this refers to islanded microgrids). It is unclear how the ESB is defining these.

Furthermore, stakeholders are being asked to comment on the Maturity Plan proposal in the absence of any governance arrangements. The Options Paper is full of phrases such as 'coordinated process to collaboratively examine', 'leverage and coordinate these efforts', 'support rapid and multi-pass engagement in each release of the process'. However, the previous 9 months of comparable process has not yet delivered a proposal or any decisions. Ideally, ESB should *not* expect stakeholders to repeat past processes unless they lead to improved results. Stakeholders cannot keep participating in time-consuming 'co-design' processes without tangible outcomes.

In sum, the 'Maturity Plan' seems to be cherry picking a number of issues already being addressed through parallel processes. It therefore appears to be duplicating effort and adding to the consultation workload for consumer stakeholders. The case for an egg timer in the NEM has *not* been made in the ESB's Options Paper and is opposed.

Part B

Essential System Services, Scheduling and Ahead Mechanisms

Having both a long-term and a short-term procurement mechanism could cause unintended consequences by locking in investments and assets that address short-term market needs at the expense of allowing for development of an optimal long-term future state. Any short-term mechanism should be designed with the long-term in mind and be compatible with an accepted vision for the future grid, which is yet to be determined. No one, to our knowledge, has set out a detailed vision for how the NEM will be structured and operated on the other side of the transition when we are approaching net zero emissions, with very low or zero contribution from synchronous generation.

In relation to the impacts on different segments of industry, it is important to recognise that the generation mix is rapidly shifting from traditional synchronous generation towards very high penetration of distributed variable renewable energy. The SSM, if included, should include and prioritise short-term structured procurement from what are currently considered variable renewables. With advances in forecasting, sensors, and predictive data analytics combined with the immediate to near-term availability of grid-forming inverters, it is quite feasible for wind and solar resources to participate in structured procurement and ahead type markets. By formulating mechanisms to provide price signals that incentivise solar and wind (and batteries) to optimise system security and reliability services can be preferentially procured from these sources through the transition. Gaining experience early, despite the steep learning curve, will be worth the investment as the transition progresses.

On the whole, the mechanisms proposed by the ESB seem reasonable. The more important issue, from our perspective, is the apparent disproportionate focus on the near term relative to the longer term. Under the UCS scenario, TNSPs are considered to be the central contracting party for procurement in the planning timeframe. However, in that timeframe, resources within the distribution networks will need to be integrated into whatever processes are used to maintain system strength in order to do full (optimal) system planning. Planning in California and elsewhere is already trying to take this perspective, by giving DER at the distribution level, for example, the opportunity to solve issues at the transmission level. Undertaking thorough whole-of-system planning will better allow efficient solutions to emerge. DER should *not* simply be a series of assumptions in the ISP; rather, planning at the transmission and distribution levels needs to be linked.

Further to this, the whole design of the ESS framework seems to be incremental, with only vague references to a slow integration of new technologies such as grid-forming inverters. The fundamental framework underlying the proposed reforms appears to be firmly grounded in the grid paradigm of the past. If we are really expecting a transition to a very high proportion of inverter-based renewable energy, then this legacy grid paradigm needs to be fundamentally changed. The proposed systems services mechanisms and markets may be relevant in the near to medium term but they will *not* adequately serve a future market that is dominated by zero-inertia IBRs. The future NEM, if powered primarily by IBRs, will need to find alternative means of maintaining stability. The pathways from today's system, through the proposed UCS and SSM mechanisms, and then on to the grid of the future, are not apparent. There is a growing consensus that the future NEM will involve more distributed control, more integration between transmission and distribution, and more consumer and end-user involvement.

The above constitutes IEEFA's perspective on ESS Part B. IEEFA has no further comment on the specific questions in relation to the ESS mechanism.

Integration of Distributed Energy Resources and Demand Side Participation

20. What are stakeholder views on the proposed maturity plan approach and priorities identified for the first release?

No argument has been presented or provided as to why an Egg Timer—akin to a Maturity Plan—is needed or is indeed an appropriate approach for developing the changes to NEM markets and network services provision to integrate DER. The Options Paper states that 'Maturity Plans are a concept used in ICT, manufacturing, and quality processes, used to help assess levels of readiness and coordination, and to provide a timetable for uplift of capabilities' but the subject is *not* an uplift of technology capabilities, it is what is needed for DER to be able to participate in current or future NEM markets.

The ESB has been using the proposed 'co-design' approach with 'sprints' since August 2020 with no tangible outcomes for market design. There are proposals for trader services, and scheduled light and multiple trading relationships (MTR) in the April paper, but none of these came out of the DER market-integration process. This ESB process promised, in August 2020, to deliver 'use cases' for DER, and 'use cases' have again been proposed with no sense of what was done with any work undertaken for the last 9 months. There appears to have been no material decisions or outcomes of the DER market design processes since August 2020. This should be of great concern to anyone interested in DER integration in the NEM.

Illustrating a sense of déjà vu, the diagram in Figure 10 in part A (the same as Figure 13 of part B) of the Maturity Plan process is almost identical to a series of such diagrams that have been presented to the ESB since August 2020.

IEEFA is seriously concerned about the current proposal for the 'egg timer' to flip over to a new set of priority issues every 6 months following a 'release'. IT development might work like this but policy, regulatory and market development does not. The NEM is not an app or a software platform. The ESB should *not* be supporting such an unsuitable process for DER market integration work.

We will focus briefly on the proposed issues to be examined through the 'egg timer' approach.

Minimum demand is a change in the supply-demand balance. It is only possibly an issue for system security in South Australia until such time as a second interconnector is built to NSW. AEMO's May 2020 report states: 'If EnergyConnect proceeds as proposed in 2023, this risk should be largely eliminated beyond that date'[40] (p.34). The engineering, economics and public policy processes surrounding the advent of rooftop solar cut-off in South Australia have been thoroughly critiqued in an IEEFA briefing note.[41] IEEFA opposes any extension of the rooftop solar cutoff regulation and practice beyond South Australia and seeks a sunset date of the operation of EnergyConnect for the existing AEMO process of cutting off solar.

From a conversation with the ESB, it appears the ESB's definition of 'active solar' is cutting off solar. However, the Options Paper writes of 'Active solar PV as market responsive by retailers and/or aggregators'. Currently, Virtual Power Plants are designed around batteries which are falling rapidly in price, as are electric vehicles (EVs). The ESB should *not* be focusing on solving (potentially) yesterday's issues when storage is changing the game and also when DOEs have the potential to be used to address any system security issues. In addition, this is not a market design issue so it is unclear why the supply-demand balance is being framed in this way. It seems to be backwards-looking, especially as there is no serious consideration of managed EV charging or Vehicle-to-Grid (V2G) in either part of the paper (in fact, neither of those terms appear in either part of the Options Paper).

'Appliance based demand response (residential)' presumably refers to the development of Australian Standard 4755. If this is the case, what is the role of the ESB in the development of this standard? As AEMO's website states, 'This standard is in the final stages of drafting and will be available for public comment prior to finalisation in the second half of 2020.'

Similarly on 'Cybersecurity, technical and interoperability standards', AEMO has responsibility for cybersecurity, there is a DEIP work stream on the development of interoperability standards, and there is an ESB rule change lodged with AEMC since September 2020 to change the governance of DER technical standards.

21. **Do stakeholders have any feedback on the approach for developing the trader-services model pathway?**

22. **What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either model?**

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[40] Australian Energy Market Operator. Minimum Demand in South Australia (SA). May 2020
[41] Gabrielle Kuiper & Steve Blume, Blunt Instrument: Uncompensated Solar Cut-Off Isn't the Only Solution to the Minimum Demand 'Problem', IEEFA April 2020

23. **How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?**

24. **What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?**

25. **Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?**

26. **Are there other options the ESB could consider on the path to support more flexible trading for end-users?**

Answers for Q 21– Q 26:

IEEFA supports the proposed trader-services model whereby there would be one registration category and a 'modular' approach to obligations based on the services to be traded from each connection point (rather than the assets). And the ESB's consideration of an additional flexible trader model seems eminently sensible given the extensive use of sub-metering in commercial and industrial buildings. IEEFA supports using a new rule change process to implement this change.

27. **Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?**

The ESB Options Paper makes the claim that 'without adequate visibility of the availability and intentions of growing demand response, very high and low prices may be managed in ways that are less efficient'. AEMO should provide quantitative evidence on these issues, in addition to qualitative claims.

Operational inefficiencies should be defined quantitatively to aid stakeholder understanding and underpin policy making. Similarly, clarity is needed regarding under what circumstances Scheduled Lite would become mandatory. It is vital that in the current circumstances of uncertainty, that any scheduled lite mechanism is voluntary.

28. **Are there any additional or alternate principles that should be considered?**

Evidence must be provided as to how the efficiency of operational decisions will be improved by Scheduled Lite.

The Dispatchability model is opposed on the grounds that it would impose significant costs on DER owners without a case as to the benefits to consumers. There is no objection to non-scheduled resources (e.g. generation/demand/DER) providing voluntary self-forecasts of future behaviour or intentions

29. Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?

Even for the visibility model, significant further work to develop this proposal should be required. We believe that the lack of quantitative evidence for the rationale or operation of the proposal is concerning. For instance, what proportion of consumers might be expected to participate, and what would be the expected increase in operational efficiency? We believe that some form of cost-benefit analysis needs to be considered before this information proposal proceeds.

It is certainly premature to move to dispatchability, especially given the future availability of distributed generation or demand response is uncertain because of unreliable forecasts of EV take-up (or stationary storage for C&I businesses installing rooftop solar), nor has there been modelling of the impact of this take-up on the level of self-sufficiency at the distribution scale.

There are important questions as to what extent DER aggregation with market participation will occur as opposed to a continuation of the current situation where retailers simply purchase distributed prosumers exported power. In addition, as the Demand Response Mechanism does not include small customers, it is unclear what the financial case will be for household demand response given the majority of small-scale consumers are *not* on cost-reflective tariffs, and also considering prices in the wholesale market are forecast to continue to fall as more renewable generation enters the NEM.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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