Response to the Energy Security Board's Post 2025 Market Design Consultation Paper

Iain MacGill[1,2], Abhijith Prakash[1,2] and Anna Bruce[1,3],

[1] Collaboration on Energy and Environmental Markets, UNSW Sydney
[2] School of Electrical Engineering and Telecommunications Engineering, UNSW Sydney
[3] School of Photovoltaic and Renewable Energy Engineering, UNSW Sydney

Corresponding author: Iain MacGill (i.macgill@unsw.edu.au)

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Dr Kerry Schott

Chair

Energy Security Board

Lodged electronically

Dear Dr Schott,

Re: Post 2025 Market Design Consultation Paper

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission to the Energy Security Board (ESB) regarding its Consultation paper on potential market design options for the National Electricity Market (NEM) post 2025.

About us

The UNSW Collaboration on Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from a range of faculties, working alongside a number of Australian and international partners. CEEM's research focuses on the challenges and opportunities of clean energy transition within market-oriented electricity industries.

Effective and efficient renewable energy integration is key to achieving such energy transition and CEEM researchers have been exploring the opportunities and challenges of market design and policy frameworks for renewable generation for several decades. More details of this work can be found at the Collaboration website. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please feel free to contact Associate Professor Iain MacGill, Joint Director of the Collaboration (i.macgill@unsw.edu.au) regarding this submission or for other CEEM matters.

Our approach to this submission

Our submission first discusses the context for the ESB's work on market design options for the NEM, and particularly our view that there is a broader design question within which this work resides and which needs to be more clearly articulated - the imperative of clean energy transition. We also consider key lessons from the NEM with regards to end-to-end market design. These insights have relevance to all of the MDI workstreams.

Our submission then addresses the Consultation Paper's questions for the seven MDIs, with a particular focus on the *MDI-C Essential System Services workstream*, which we see as the most important work being undertaken by the ESB at present.

While time did not permit a more complete submission, we would of course be very happy and interested to discuss our views on all the workstreams, and the associated questions for consultation, if that is of interest to the ESB.

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Introduction

A. Role for electricity markets in Australia and beyond

We welcome this opportunity to contribute to the work of ESB and stakeholders on the future of the Australian National Electricity Market (NEM). In reality, of course, the NEM is not national in extent, although it does serve around 90% of Australian energy consumers. It is also primarily an interconnected power system joining five formerly state based electricity systems. However, the NEM does involve largely harmonised market arrangements across this long, ‘stringy’ and near national, power system. Still, these market arrangements are only a means, not an end in themselves. As with all ‘means’, they need to justify themselves through delivered outcomes and if they are failing in this regard, other approaches need to be considered.

We certainly agree with the ESB that current NEM arrangements do not appear to be fit for purpose, particularly given the unprecedented growth in both utility scale and distributed renewables across the NEM over the past decade. The adequacy of these arrangements does, however, critically depend on what comes next. For example, utility wind and solar projects are increasingly under a cloud in the NEM, while distributed PV continues to grow very strongly but the context for deployment is becoming more complex and some changes underway or proposed may well make it less attractive for energy users to invest.

We consider NEM performance to date later, however, more generally, it is important to note that electricity markets alone are still playing a relatively limited role in driving the global electricity industry investment necessary to address our shared energy and climate challenges. The International Energy Agency’s (IEA) assessment of global power sector investment by remuneration mechanism suggests that only 3% of the total $750 billion invested in 2017 was purely driven by wholesale market pricing alone. There was approximately thirteen times greater regulated investment (mostly networks), almost four times more distributed generation investment under retail/regulated tariffs and roughly fifteen times more regulated/contracted utility generation investment driven by government policy mechanisms.

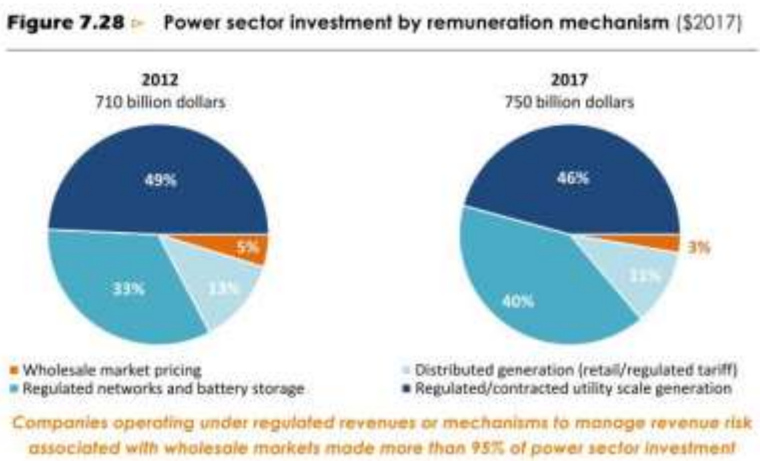

Figure 1: Global power sector investment in 2012 and 2017 by mechanism[1]

While Australia was an early and enthusiastic adopter of electricity industry restructuring, it seems likely that much of the generation investment seen over its twenty years of operation was driven by government owned participants (e.g. Queensland coal plants), or government incentives, including the Renewable Energy Target and various schemes supporting lower emission gas-fired generation. This is

[1] International Energy Agency (IEA), *World Energy Outlook 2018*, available at www.iea.org.au.

key context for the work of the ESB, yet doesn't receive sufficient attention in this *Consultation Paper*, or the design process underway more generally.

The *Consultation Paper* notes that current set of systems, tools, market arrangements and regulatory frameworks is no longer entirely fit for purpose and able to meet the changing needs of the system and customers. Moreover, we suggest that the broader energy policy framework within which all these arrangements reside is clearly not fit for purpose. While we appreciate the scope for this ESB work doesn't directly incorporate this wider perspective, the design work it has underway would greatly benefit from greater attention to it. The Consultation Paper does note that the ESB is tasked with developing a market design that delivers "secure and reliable power at least cost to consumers, and accommodates the changes underway and expected in the future."

The latest IEA World Energy Outlook's key messages seem highly relevant to our understanding of this broader context around likely and possible energy sector changes in the future. They include:

- The pandemic is far from over and many uncertainties remain. Today's policy setting do not produce a decisive break in the outlook for CO2 emissions but a more sustainable recovery is possible.
- Meanwhile renewables are taking power, particularly solar, yet weak grids could prove to be an Achilles heel.
- Enhanced clean energy policies could make 2019 the peak year for energy related emissions
- We need to almost immediately end new emissions intensive energy investment to avoid a global temperature rise above 1.5°C.
- Critically, "Transitions depend on government actions but more than 70% of related investment [globally] could come from private actors."
- Also, "Net-zero pledges for 2050 and earlier are already essential to the Sustainable Development Scenario; achieving global net-zero emissions by 2050 would require a dramatic extra push."
- "Behavioural changes are essential to achieve the scale and speed of emission reductions required [for net zero emissions in 2050]"
- "If energy transitions are not secure then they will not be rapid either."

Much of the work program identified by the ESB across its seven workstreams is consistent with these key global insights. However, it also suggests the importance of broader scoping of the work:

MDI-A Resource adequacy mechanisms: Clean energy transition needs frameworks for driving investment that ensure resource adequacy, but also investment for clean energy transition if globally agreed environmental objectives are to be achieved.

MDI-B Ageing thermal generation strategy: While it is certainly important to manage retiring thermal plant, its prompt exit is essential for our clean energy transition challenge.

MDI-C Essential system services: Security is, and needs to be, a key priority for energy transition. Widespread failure is not an option and changes that might improve efficiency but put security at risk may well not be worth the risk. However, failure to deliver rapid energy transition also involves great risks.

MDI-D Scheduling and ahead mechanisms: These are important but transitional issues in any major clean energy transition given the limited longer-term role for the conventional thermal plant that most requires assistance in managing its limited operating envelopes around plant starts and stops, and minimum operating levels.

MDI-E/F Two sided markets and Valuing demand flexibility and integrating DER: These workstreams aren't just an opportunity to deliver better outcomes for energy users but have a key role to play in facilitating the behavioural changes required for transition.

MDI-G Transmission access and the coordination of generation and transmission investment: While this workstream does perhaps provide an opportunity for improved efficiency of investment in both generation and networks, there are key risks with weak grids, perhaps an outcome of introducing complex new transmission access and pricing that delay investments that might greatly reduce the value of renewables for the NEM.

What is missing? - a workstream integrating all of this work with analysis of different policy frameworks capable of delivering the clean energy transition that is almost certainly required to avoid dangerous global warming. It is notable that the IEA now sees the need for a net zero emission scenario for 2050. Australia may well need to start planning for this eventuality by 2020 given the growing number of countries adopting such targets.[2]

B. End to end market design

The joint IEA/ESB/ERICA Future Energy Market Summit in late 2019 included a session addressing the question of *An end to end approach for market design that integrates utility generation and transmission, variable renewables and a rapidly evolving distribution network with distributed energy resources.* Here we extract seven key lessons and enduring challenges that emerged from this discussion and the consequent paper arising from this Summit Session[3]:

1. End-to-end electricity market design is a 'markets' integration challenge

End to end market design is, in reality of course, a multi-market design challenge. A key part of market design, therefore, is actually designing the interfaces between these multiple markets so that they can perform efficiently.

Furthermore, a single inefficient market can adversely impact the efficiency of others. The principle of sub-optimisation holds that "optimizing each subsystem independently will not in general lead to a system optimum, or more strongly, improvement of a particular subsystem may actually worsen the overall system" This would seem to be a real risk for regulatory and market design in the NEM and some of the proposed ESB changes.

Designing these interfaces can be particularly challenging when key markets lie outside formal market design processes. A pertinent example in the NEM are the derivative markets which play a key role in managing forward looking operational decision making and investment, but which are not formally managed by the NEM governance arrangements. The ESB might usefully give further consideration to possible derivative market interventions, perhaps through the Retailer Reliability Obligation.

2. It isn't clear where the ends lie in end-to-end market design

Effective and efficient end-to-end market design for achieving a reliable and secure, low emission and low-cost electricity industry remains hostage to possible inefficiencies in markets at the ends. A pertinent example for the NEM are the present gas market arrangements which involve a relatively

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[2] Investor Group on Climate Change, *Mapping Australia's net zero investment potential*, IGCC Policy Update, October 2020.

[3] Iain MacGill and Ryan Esplin (2020) "End-to-end electricity market design – lessons from the Australian National Electricity Market," *The Electricity Journal*.

small number of players in supply and transport and does not appear to always be delivering competitive pricing.

Of likely even greater importance is the other end of end-to-end market design – the demand-side. The formal National Electricity Objective is "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity…" Very few electricity consumers are interested in electricity as a 'market' commodity but, instead, are interested in the 'energy services' that the industry provides. Sub-optimal levels of energy efficiency-oriented decision making by consumers means inefficient electricity industry outcomes.

3. End-to-end market design requires broader policy and regulatory 'side-to-side' design

NEM redesign resides within a broader design challenge across technical, regulatory and external policies. Key technical and regulatory aspects of the electricity industry include transmission and distribution network planning, generator performance standards and at least some aspects of the security regime. The interface between these decisions and commercial market arrangements is not always clear. For the NEM, a pertinent example is primary frequency response which has both some mandatory as well as market oriented (FCAS) requirements, and has seen some adverse impacts from the interaction between these.

Another relevant example is renewable energy policy support mechanisms. As AEMO amongst others has noted, the use of tenders/auctions for supporting renewable generation may have some very attractive design aspects in terms of reducing renewables project costs, but can mean that renewable project owners and operators do not see 'energy market' signals regarding the locational and temporal value of the highly variable generation that they provide. Savings on project costs must be weighed against potentially higher integration costs.

More generally, end-to-end and side-to-side design invariably involves greater levels of uncertainty, and hence needs to focus on robustness and resilience – the ability to perform reasonably well under a wide range of possible futures. Comprehensive and coherent market design alongside technical/regulatory and policy development is key, with a particular focus on interfaces between these decision making regimes.

4. Markets with major externalities are inefficient by design

Unless these externalities are addressed through other means. Market design processes that ignore externalities are therefore inefficient by design. The electricity sector, however, invariably has a wide range of externalities, and their costs and benefits likely outweigh direct industry costs. While sector greenhouse gas emissions are a key environmental externality in all electricity industries, as an input to almost all forms of economic activity, electricity also provides large economic and societal benefits that are not fully reflected in market pricing either.

There are a range of mechanisms to 'shadow' price some of these externalities including renewable energy policy efforts should a nation-wide carbon price not be politically feasible. Renewable feed-in tariffs, green certificate schemes and suitably designed tender mechanisms can all be used. Still, there are many externalities where there seems to be little chance of explicit interventions – carbon pricing or otherwise – sufficient to address the costs of the externality on society. Electricity market designers face the challenge that markets with major externalities are inefficient by design. Worse, efforts to improve the efficiency of some parts of an electricity market with such externalities might actually reduce overall market efficiency. Fortunately, there are options for market designers to incorporate externalities into their design processes. Shadow pricing is one such option and has been applied in some regulatory processes in Australia and elsewhere. The ESB could consider opportunities to incorporate this into their assessment frameworks.

5. Technology change and market design can both reveal currently ‘unpriced’ industry costs and benefits, particularly in security services

As noted in the ESB paper, system security services such as inertia and system strength have conventionally been supplied as a by-product of the operation of synchronous coal, gas and hydro generators. The displacement of such generation by non-synchronous wind and solar has now revealed the importance of these formerly freely provided services. A mix of regulatory and market-based approaches will be required to now acquire these services in an efficient manner from a potentially wide range of market participants. They will need to be integrated into existing arrangements – ideally co-optimised, although excessive complexity brings its own problems

Secondly, different market designs, and the introduction of markets, can also see services that market participants provided as a condition of their participation suddenly being seen as something that requires incentives. This feature of market design and its implications for ‘social norms’ of participation requires greater attention.

6. The key design challenge in end-to-end market design is the market and regulatory interface with energy consumers

It is widely appreciated that market efficiency is improved by active participation on the demand side, and a range of technology developments in metering, control and communication have improved the capability for greater energy consumer engagement. Of perhaps even greater importance are the range of distributed energy resources now available to consumers including rooftop PV, smart and flexible loads, battery energy storage and electric vehicles.

However, the present industry interface with almost all energy consumers, and certainly small consumers, is inadequate to the task of appropriately coordinating distributed energy resource and demand-side participation. In particular, pricing for electricity consumption and, where relevant, DER export have meant that small consumers have not received pricing signals to appropriately coordinate their electricity consumption decisions.

In the NEM, there are currently two general frameworks for better integrating consumers into market arrangements. One is to send wholesale market prices down to consumers as ‘spot’ market tariffs, and there are some innovative new retailers offering such tariffs. More generally, the last six years have seen efforts to make network tariffs more cost reflective by encouraging greater use of time-of-use tariffs and introducing new tariff structures with peak demand (or capacity) charges. The other framework has been to aggregate consumers to formally participate in wholesale market arrangements. One early success has been DR aggregator participation in FCAS markets.

Both general approaches show potential. At least some consumers are increasingly ‘ready, willing and able’ to respond to wholesale market and network tariff signals. However, existing tariff arrangements for small consumers have been more of a social than economic ‘construct’ with wide societal acceptance of some wealth transfers – for example, subsidising electricity costs for regional and rural consumers. Many consumers have little interest in complex tariffs and the engagement required to benefit from them. Aggregating consumers up to existing, and potential new future, market arrangements is also a key opportunity but there are limits to what it can achieve. The NEM currently has limited locational pricing, opaque derivatives, market power concerns and major externalities. Meanwhile, the network businesses face some conflicts of interest in facilitating a greater role for distributed energy resources, and it seems that some of the key value for consumer engagement is actually at the local network level. This may require that distributors increasingly participate in the provision of non-monopoly services.

A focus only on these frameworks also risks missing the broader opportunity. Energy consumers need support to engage effectively, and the most appropriate interface is one focused on their ‘energy services’. The missing market players, therefore, are energy service providers focussed on meeting consumers’ diverse energy service needs in the most efficient, reliable and secure manner. This might be better reflected in the ESB workstreams.

7. Widespread market failure is not an option in the electricity sector – end-to-end market design also requires design of 'alternative' frameworks

The electricity market is 'too big (and too important) to fail'. It is inevitable that governments at a state and federal level will have continued involvement in the electricity sector given the enormous economic and societal role it plays. This will particularly be the case during periods of high prices or low reliability. An example for the NEM was the aftermath of the South Australian Blackout in 2016 which saw the State government undertake a range of 'non-market' interventions.

AEMO formally places system security and reliability ahead of market outcomes, and there is a sophisticated framework for assessing when market arrangements don't provide sufficient assurance that these will be delivered. However, the challenges of major electricity industry transition don't seem likely to get any easier for the foreseeable future, so greater efforts on planning for possible major 'market' failures, and possible alternatives, seem likely to be required.

Comments on Section 2 of the Consultation Paper

A. The existing NEM

This Section provides a useful summary of the existing NEM and emerging challenges. We note that the original design of the NEM specifically managed aspects of the transition to more market oriented arrangements, and the transition benefited from circumstances including significant generation capacity overhang from the overly-ambitious investment plans of several State Electricity Commissions. Actions to assist the transition to the NEM included strategic transmission investment in some locations, notably Queensland. It also used a range of vesting 'derivative' contracts to manage the risks of transition to markets. Given the risks in the present NEM, both the strategic transmission investment and government mandated risk management deserve further attention in this design process.

There was also some early innovation in energy user engagement prior to the NEM, including the widespread deployment of ripple control hot water systems in over a million. Indeed, the introduction of the NEM actually reduced energy user engagement in some regards including seeing the winding up of some major demand management initiatives being run by several State Commissions[4]. Finally, the National Grid Management Council (NGMC) did consider formal design of the derivative markets to support investment, however, they were eventually established outside of formal NEM arrangements (other than for Settlement Residue Auctions) - an outcome with almost certainly adverse impacts on the transparency and effectiveness of these key markets for investment.

The claim that the NEM "..has served the nation well until the last few years." seems questionable given outcomes in recent years including the highest ever wholesale prices seen over the 20 year life of the NEM, retail prices that are amongst the highest in the world (on an exchange rate basis), growing security concerns and amongst the highest emissions intensity of any electricity industry globally. However, it is notable that the past few years have seen prices fall while reliability has been largely maintained. Also notable is the extraordinary progress on reducing the NEM's emissions intensity through major wind and solar deployment- a very worthy outcome.

Also missing from the Consultation Paper is discussion of the implications of NEM structure (the number and nature of market participants) as well as market design on future NEM outcomes. It is extremely challenging to design efficient markets where large incumbents dominate the market. The absence of such discussion is, therefore, concerning.

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[4] MacGill, I., & Healy, S. (2013). Is electricity industry reform the right answer to the wrong question? Lessons from Australian restructuring and climate policy. In *Evolution of Global Electricity Markets* (pp. 615-644). Academic Press.

B. Meeting consumer needs

The *Consultation Paper* notes that energy consumers are not convinced that the market is working in their long-term interests. And we are agreed that their ability to deploy DER on fair terms is a key expectation. While it has raised challenges, it should be noted that residential, and more recently commercial, uptake of distributed PV has played an enormously valuable role in both reducing electricity sector emissions while also engaging a growing proportion of energy users in their energy provision.

We are also agreed that market design should focus more on energy users in all their diversity. It is important to note the electricity industry's framing of energy users has changed markedly since its early development over 120 years ago, from:

- *Clients* - with early tailored industrial or commercial (lighting) applications with service oriented contracting arrangements, to:
- *Citizens* - with electricity being seen as an essential public good, driving efforts such as rural electrification with socially constructed tariffs, to:
- *Consumers* - as served by vertically integrated utilities of growing size and scope with overall cost-recovery objectives via socially constructed, tariffs, to:
- *Customers* - as framed in electricity industry 'reform', liberalisation and restructuring with more market oriented energy 'pricing' and supposedly cost-reflective network tariffs, to perhaps now:
- *Partners* or even competitors to the supply industry through deployment of DER.

The NEM now must supply energy users who fall within all of these framings, from the unengaged to prosumers. Also, a key opportunity to improve energy user outcomes is to assist them with decision making around energy efficiency. The ESB might consider more formal frameworks of energy user segmentation and the arrangements needed to assist them in meeting their energy service needs, rather than focussing, as is currently the case for the industry, on kWh exchange. UNSW and Monash University are leading Australian participation in the International Energy Agency *User Centered Energy Systems* Technology Collaboration Program which is focussed on reframing electricity industry solutions around energy users[5].

C. Managing variability and uncertainty

As the paper notes, variable renewable generation has the potential to drive down both emission and supply costs, something noted by the IEA's latest World Energy Outlook. We are agreed on the challenges facing AEMO with growing variable renewable penetrations - both utility and distributed. The complexity is growing, as is the need for tools to assist in managing this. One thing not flagged in this section of the report that is also contributing to growing variability and uncertainty is the falling reliability of aging thermal plant. This is greatly adding to AEMO's challenges in securely managing the system, particularly given that thermal plant failures are more likely during the extreme weather events that also drive NEM peak demand periods[6].

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[5] www.userstcp.org

[6] A number of reports from The Australia Institute present analysis of thermal plant failures in the NEM - see www.tai.org.au for more details.

D. Need for capital replacement

It should be noted that capital replacement is only part of the challenge that the NEM faces - clean energy transition may well see increased demand as sectors such as transport are increasingly electrified, and where emission reductions must be accelerated.

The investability of dispatchable resources is rightly a key design concern. While the *Consultation Paper* flags the role of externality risk (including presumably policy risk associated with addressing these externalities) as well as technology and demand risks, it doesn't emphasise how clear, ambitious and legislated policies for clean energy transition could certainly assist in addressing these risks.

While the *Consultation Paper* also flags that "it is also important to consider increasing the location signals for generation investment to ensure optimal investment and use of transmission", we consider that this is at best a secondary issue, and realistically yet another source of uncertainty for the investment required for clean energy transition.

E. Need to value demand flexibility and integrate DER

The extraordinary uptake of distributed PV in the NEM is without doubt one of the greatest opportunities yet also challenges facing NEM policy makers seeking affordable, secure and environmentally clean electricity provision.

The *Consultation Paper* states that the current approach to integrating DER has largely relied on fixed feed-in tariffs . We question the accuracy of this statement given that consumers in most states face different retail offerings placing different values on exported PV. Furthermore, these feed-in tariffs are considerably lower tariffs than the savings earned by energy users when their PV generation reduces their consumption rather than being exported - an outcome which does already send some pricing signals to PV owners to try and maximise self consumption, hence reducing adverse network impacts. However, the falling costs for rooftop PV have certainly seen growing exports from PV households, with impacts on 'net' system demand, and particularly minimum net system demand.

There is no doubt some trade-off between network investment to reduce these DER impacts and opportunities to shape DER deployment and operation to reduce these impacts. However, considerable further work still seems required to establish the most appropriate balance of these options[7].

Responses to Consultation and Submissions Questions

1. The potential solutions and how well the characteristics of these solutions address the challenges identified with the current market design. Where alternative solutions can be identified for discussion, these would also be welcome.

   See detailed comments in the Introduction. Our main concern is more around the question formulation posed the ESB, which as discussed above appears to miss the key challenge that the new market design needs to address: the ability to deliver clean energy transition over what is now a matter of several decades. The proposed timing of the implementation of the changes to the market design and reasons for any alternative timing you may wish to propose. Noting the answer to 1. the proposed priorities around the timing of changes seem reasonable. The timelines seem extremely ambitious for such wide ranging design work, particularly as Covid-19 crisis has bought some additional time for at least some of these challenges.

[7] Heslop, S.F., Stringer, N., Yildiz, B., Bruce, A. , Heywood, P., MacGill, I., Passey, R (2020) *Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market,* CEEM report for the ESB.

2. Our proposed approach to classifying the broad range of consumer needs, and what may be alternative or complementary incentives or regulatory measures (including consumer protections) to consider in support of these needs.

See the discussion on consumers in Section 2 above.

3. The proposed approach and criteria to evaluate the range of potential solutions identified within each workstream, as well as for assessing market design option(s) to be developed later this year.

The assessment criteria identified by the ESB are as follows:

Assessment criteria	Description
1.Facilitate effective outcomes for all consumers - via competition where efficient and complemented by effective consumer protections and regulation where appropriate.	Rivalry in competitive markets should promote efficiencies and innovation, but should be complemented by effective consumer protection regulations to mitigate against poor or misleading conduct, and to protect those who are vulnerable or unable to safeguard their interests. Frameworks should also ensure that regulated entities such as network monopolies are subject to effective economic regulation that promotes efficiency, reliability, system security and safety.
2. Promote signals for efficient investment and operations	Efficient arrangements maximise the provision of price signals that reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities, in order to encourage timely and efficient decision-making in both investment, demand and operational time-scales. Efficient outcomes will be enabled across productive, allocative, technical and dynamic dimensions, supporting more efficient and effective use of capital and energy. While price signals are preferred, there may be other signals that can also be provided such as the greater provision of market information to participants.
3. Appropriate cost and risk allocation	Risk and cost allocation, and the accountability for investment and operational decisions should rest with those parties best placed to manage them.
4. Technology neutrality	Regulatory arrangements must be flexible to changing market conditions and take into account the full range of potential market and network solutions. They should support the right mix of resources over time, reflecting supply and demand side participants and solutions, technological developments and changes in behaviour, rather than be designed solely for the prevailing technology or business model of the day.
5. Cross-market integration	Costs to consumers will be minimised when markets complementary to energy, such as ancillary services and emissions, are designed in a way that is consistent with the price discovery mechanism in the electricity market.
6. Regulatory and administrative costs	Practical, operational and compliance impacts result in minimal unintended consequences. Changes to regulatory frameworks come with associated costs. These costs include both those imposed to implement change and the ongoing costs associated with making the change.
7. Ability to deliver a reliable system and support system security	Security and reliability challenges need to be considered as supply and demand become more variable and uncertain, and the industry transitions away from generation that traditionally delivered security services.

While these represent a reasonable set of assessment criteria, there are questions and limitations in the way they are posed, and a key criteria is missing in our view.

1. *Effective outcomes for all consumers:* Competitive markets should promote efficiencies and innovations but there have been challenges for establish effective competition in electricity industries, certainly from the perspective of consumers. The need for regulation certainly encompasses consumer protection but goes well beyond this. High levels of regulatory and policy intervention by governments are a reality of restructured electricity industries around the world, reflecting their high social welfare and economic importance. This goes beyond the network regulation that is flagged.

2. *Promote signals for efficient investment and operations:* efficient pricing is of course key for effective market outcomes. However, the formulation that marginal costs are the best basis for pricing is a limited viewpoint, particularly in terms of the future prices relevant for investment decision making (long run marginal cost is a highly problematic concept) and for achieving dynamic efficiency in its broadest sense, including facilitating major transitions.

3. *Appropriate cost and risk allocation:* Markets certainly have a key, and often neglected role, in allocating risks as well as costs and benefits. The argument that risks should be placed on parties best placed to manage them is right in a limited sense. However, a more useful framing includes:
    a. Which party is best able to control or manage the occurrence of the risk?
    b. Which party is best able to control or manage the impact of the risk?
    c. For a particular risk, which party has a greater incentive to develop risk mitigation strategies, either to control the occurrence of the risk or its impact?
    d. For risks that are typically allocated to the public party, might there be innovative opportunities to reduce whole-of-life costs by allocating (even if only partially) the risk to the private party?
    e. Which risk allocation would result in the lowest whole-of-life costs?
    f. Which risk allocation incentivizes preventative risk management, as opposed to reactive risk management?

    In the end, some of the risks associated with energy transition will fall upon governments and hence be effectively socialised. A key risk however is privatising the gains and socialising the losses.

4. *Technology neutrality:* an important objective that was incorporated in the original National Grid Management Council design specification for the NEM. However, great care needs to be defining technology neutrality, particularly when there are unpriced externalities associated with different technology choices. It is also a particular challenging for emerging technologies given the role that incumbents play in design processes such as this. Not only are these technologies often not at the table, they then risk being on the menu. Particular challenges for the NEM are technology neutrality between supply versus demand and large versus small. It is also notable that the NGMC design specification noted the importance of participant neutrality, both between incumbents and new entrants, as well as publicly owned versus private participants. This would be a useful addition to the ESB criteria.

5. *Cross market integration:* Again, we agree that this is an important criteria although the question of which market arrangement should take preference. For example, mechanisms to reduce emissions can be designed to fit with energy market pricing discovery and there are important efficiency gains from this. Conversely, however, if there are particular efficiency gains in terms of reducing investment costs, e.g. the use of auctions for renewables projects, these benefits might outweigh any adverse impacts on energy pricing.

6. *Regulatory and administrative costs* certainly need consideration. However, transaction costs associated with market arrangements can also be significant. It isn't clear these are included in the above definition, and they might be better highlighted in this assessment framework.

7. *Ability to deliver a reliable system and support system security:* Agreed, however, it could be explicitly noted that this needs to be achieved despite considerable uncertainty regarding the outcomes from different changes. Robustness in terms of system reliability and security outcomes during potentially major energy transition is really the key criterion here.

Responses to Market Design Initiatives Questions

A. Resource Adequacy Mechanisms (RAMs)

This is a key MDI - widespread failure is not an option and rapid, effective and efficient investment is the key to clean energy transition. Having said that, experience in other electricity industries has highlighted the risks of poor designed RAMs.

The Consultation Paper does state that current signals for investment are underpinned by expectations of future prices. While almost all investment does involve 'expectations' there is a key role for mechanisms that allow investors to 'lock in', if only partially, future prices.

Risk, as the paper notes, is the key factor. Simply put, the cost of key new generation options including renewables and storage is mostly the cost of capital, and the cost of capital is mostly the cost of finance, and the cost of finance mostly depends on risk.

The Paper flags investor concerns about government interventions. In our view these are inevitable given the electricity industry's essential role in social and economic development. It can be argued, indeed, that governments need to intervene given the wide range of externalities - both positive (e.g. social welfare) and negative (e.g. environmental) that aren't currently priced in electricity markets.

While this does impact private investment signals, such interventions may not mean "consumers will pay more than necessary for investment". In reality, the low-cost finance available to governments may deliver significant savings for energy consumers if their investments are suitably guided. Alternatively, there are a range of mechanisms by which governments can reduce risk for investors to get project costs down such as renewable energy auctions/tenders. These savings need to be balanced against the potential costs of such risk allocation, and integration costs.[8]

The drivers of uncertainty flagged in the Paper are many including uncertainties around retirement of existing plant, flat lining demand and the risk of major load departures. Certainly, demand growth has historically meant that the main risk in generation investment was investing too soon. Note that clear government commitment to clean energy transition would assist in this regard by making it clear that high emission plant will have to depart over the next two decades, while electrification of other energy consuming sectors such as transport will add to demand. Hence, one of the clearest opportunities to improve investment outcomes is for governments to commit to clean energy transition and begin implementing policies to deliver it.

1. Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?

It is unclear whether current arrangements are sufficient. Firstly, as noted above, the NEM commenced at a time of significant generation capacity overhang, an outcome of excessive investment by a number of State Electricity Commissions over prior decades.

Also, while there has been considerable generation investment in the NEM over its two decades of operation, it is questionable how much arose purely from private investment based on the wholesale market and associated longer-term derivative contracts. Coal generation investment in Queensland mainly involved State owned generator participants, investment in CCGT was almost certainly impacted

[8] I MacGill, A Bruce, S Young (2019) "Renewable energy auctions versus Green Certificate Schemes—lower prices but greater integration costs?." In *Proc. 2019 IEEE Power & Energy Society General Meeting*, Atlanta.

by the Queensland 13% Gas Scheme and the NSW GGAS, while almost all renewables investment has been driven by some mix of Federal and State Government deployment policies.

As such, we have little experience to draw upon in assessing current resource adequacy mechanisms without these 'external' drivers. However, the fact that the most market driven generation investment in the NEM has likely been for OCGTs highlights some potential with these arrangements to drive investment in flexible dispatchable generation. A particular difficulty we face in the NEM is the poor transparency of key derivative markets, certainly for longer-term contracting.

Beyond this, climate change imperatives require extraordinary investment in renewables and flexible resources over the next two decades. There is little reason to believe current arrangements can assure effective and efficient delivery of this investment. As noted above, global power sector investment driven by wholesale markets was estimated to be only 3% of total expenditure in 2017. This is the reality of investment in the electricity sector. Furthermore, key externalities including environmental harms are still unpriced, or inadequately priced, in electricity markets around the world, making such government intervention appropriate, indeed necessary.

2. Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?

We have commented on the proposed operating reserves mechanism in MDI-C. In terms of how effective short-term signals from such a mechanism can be in delivering investment, much depends of course on the effectiveness of the OR design and implementation.

There is certainly value in establishing efficient short-term operational signals reflecting the value of essential system services. Such signals can 'reveal' existing capabilities associated with new ways of operating available power system resources that don't require any, or major investment - for example, demand-side flexibility.

However, investment is only driven by short-term prices to the extent that they likely reflect future prices, or where there are financial contracting instruments that allow participants to lock in future prices prior to investment. Operating Reserve design should therefore explicitly address how associated derivative or other future pricing instruments might be established.

3. Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?

There are 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. The latter issue particularly highlights the challenges of market design (establishing the rules) when the industry structure (ownership of participants) is highly concentrated. This has not received sufficient attention in the ESB work to date - it is extremely difficult to design effective and efficient markets with high market concentrations given the key role that competition plays in delivering good outcomes within market frameworks.

4. Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?

This is a complex question. The key point with backstops such as the RERT is that their primary role is to ensure robust market operation despite all the future uncertainties that may adversely impact the operation of the 'default' arrangements. While duplication in policy frameworks is generally argued to reduce efficiency, in practice it can be entirely appropriate when widespread failure is not an option. Framing the ESB market design work to focus more on robustness rather than efficiency would in our view improve the outcomes of the work.

5. Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?

This is an excellent question, that should really receive greater attention than it currently seems to receive in the ESB's work, and certainly this Consultation Paper. As note d above, broader government policies are not only inevitable, but necessary given all the externalities that are currently unpriced in the market arrangements. Unpriced externalities make electricity markets inefficient by design, and create the risk that efficiency improvements in some areas of the market design may actually make the industry less efficient overall.

As discussed above, we have concerns about the current RRO design, which may limits 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.

B. Ageing Thermal Generation Strategy

1. Have we correctly identified the cost, reliability and security risks to consumers from the transition away from thermal generation?

Clean energy transition requires that existing coal plant depart in an orderly, but timely manner over the next two decades. However, it is notable that a considerable proportion of our gas generation fleet will also be required to depart over this time if ambitious climate change emission reductions are to be achieved. As such, a key risk is that the plants don't depart quickly enough, and it is not enough to rely on rising ongoing plant costs and forecast revenue to drive exit.

As the Paper notes, there are specific risks associated with unexpected and sudden major technical failures that might result in plants leaving regardless of any stated plans and commitments. Flexibility in which plants retire in which order could assist in managing these risks.

2. Are these risks likely to be material, particularly those relating to consumer costs?

Consumer costs are only one of the risks associated with the timing of thermal plant exit, but certainly the risks are material for that, as well as for environmental and other outcomes.

3. Are there additional or alternate market design approaches that will ensure the transition away from thermal generation is least cost to consumers?

There are additional or alternative market design approaches, however, none of these or the options identified by the ESB can 'ensure' the transition away from thermal generation is at least cost to consumers. Instead, our objective should be a series of measures to ensure that aging thermal plants depart in an orderly, yet relatively quick timeframe. This would seem to call for a schedule of plant departures determined through a centrally coordinated process, with perhaps associated policy measures, rather than relying on the owners of these assets to somehow arrive at a suitable schedule independently.

4. Should the ESB consider and develop any of the options outlined in this section further?

In our view, more detailed analysis is required across the options presented, particularly that of the Grattan Institute. However, a wider set of option with greater central coordination should also be considered.

C. Essential System Services

We have divided our response to the content within Market Design Initiative C – Essential System Services into three main sections. Section I outlines our perspective on the problems the ESB is trying to solve, the outcomes of good ESS market design and the challenges faced in achieving these outcomes. This frames a discussion of the solution framework proposed by the ESB and provides a basis for our responses to the questions posed by the ESB in Section II. In Section III, we briefly discuss this market design process and its interaction with rule change proposals currently being considered by the AEMC.

We should note that our work in this area is ongoing, and there is much still to be done to better understand the challenges and opportunities for effective and efficient delivery of ESS. We would welcome the opportunity to discuss our preliminary insights with the ESB and other stakeholders.

I. A broader view of the problem and solutions

a) Two classes of problems

We propose that there are two classes of ESS, and hence two classes of problems that this initiative is trying to address:

1. As outlined by the ESB, the retirement of synchronous generators in conjunction with growing penetrations of asynchronous inverter-based resources has contributed to the need to explicitly procure ESS such as inertia and system strength. One way in which these ESS can be provided is as by-products of energy generation from synchronous generators. Given that synchronous generation was the dominant form of generation at the inception of the NEM, the procurement of these ESS was therefore not explicit in the NEM's original market design. We discuss the definition and nature of these ESS and potential approaches for their procurement in response to Question 3.
2. Other ESS, namely frequency control services and operating reserves, are either implicitly or explicitly made available to AEMO through current energy or Frequency Control Ancillary Services (FCAS) market arrangements. To some extent, we concur with the ESB's opinion that "the current arrangements are not providing adequate signals for efficient operational scheduling" to provide these services, "nor for investors to respond to these needs"[9].

b) Good design outcomes

Prior to discussing potential solutions to these problems, it is important to define desired outcomes of the design process. Below, we present three outcomes that have previously been proposed for designing ESS arrangements both in the literature and by the AEMC[10]:

1. **Effectiveness**. This entails both sufficient quantity and performance of procured ESS to ensure that power system requirements are met.
2. **Efficiency**. Efficient ESS arrangements will procure services at the lowest cost to the system, both now (*productive* efficiency) and into the future (*dynamic* efficiency). Furthermore,

[9] Energy Security Board, "Post 2025 Market Design Consultation Paper," 2020, 60.

[10] Yann Rebours, Daniel Kirschen, and Marc Trotignon, "Fundamental Design Issues in Markets for Ancillary Services," *Electricity Journal* 20, no. 6 (2007): 26–34, https://doi.org/10.1016/j.tej.2007.06.003; Reinier A.C. van der Veen and Rudi A. Hakvoort, "The Electricity Balancing Market: Exploring the Design Challenge," *Utilities Policy* 43 (December 2016): 186–94, https://doi.org/10.1016/j.jup.2016.10.008; Australian Energy Market Commission, "System Services Rule Changes - Consultation Paper," 2020.

efficient ESS arrangements should also procure the right mix of services according to user and/or system needs (*allocative* efficiency).

3. **Minimising procurement costs and complexity**. This outcome is often overlooked. Procurement and verification of delivery of ESS may involve significant costs associated with facilitation and monitoring. This could include metering equipment, IT systems and additional staffing costs. Complex ESS procurement arrangements may also have unintended and unforeseen consequences on processes and markets that interface with these arrangements, such as the energy market and existing FCAS markets[11].

c) Challenges to achieving good design outcomes

Achieving these outcomes is challenging due to the characteristics of ESS. ESS are either public goods or, in the case of system strength and voltage control, common pool resources that are subject to rivalry in the presence of network congestion[12]. As such, it can be challenging and complex to allocate ESS costs through a 'Causer Pays' or 'User Pays' framework and for market-based mechanisms to produce ESS prices that recognise the true value of the service to power system users alongside any opportunity-costs incurred by the supplying participant[13]. The latter is particularly difficult to achieve as there is a tension between the relatively low marginal opportunity-costs of existing synchronous generation providing ESS and the strong price signals needed to incentivise new capabilities, particularly from high capital, low operating cost inverter-based resources (IBR).

Appropriate price formation should support both operational provision of ESS and the investment in capabilities to provide them. Efficient cost-allocation can provide incentives to reduce the need for ESS and create counter-parties for hedging instruments that further strengthen price formation[14]. Both of these should lead to "efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers of electricity with respect to…security of the national electricity system" as stated in the National Electricity Objective.

An equally important consideration are the trade-offs associated with the separation and fungibility of ESS. Market-based mechanisms will work best when a particular ESS is a fungible and well defined, or "discrete", commodity supplied by various providers[15]. With a sufficiently large market, prices should reflect the costs incurred by various providers to provide such a service[16]. This, however, ignores the wide "spectrum" of technical capabilities of power system resources with respect to frequency and voltage control and stability. Restricting the definition to an ESS product to achieve fungibility could improve the efficiency of a particular service's market-based mechanism but may restrict or fail to incentivise higher quality provision and thus may lead to an inefficient overall outcome for the power system.

d) Our views on the ESB's solution framework

[11] Iain MacGill and Ryan Esplin, "End-to-End Electricity Market Design - Some Lessons from the Australian National Electricity Market," *Electricity Journal* 33, no. 9 (2020): 106831, https://doi.org/10.1016/j.tej.2020.106831.

[12] Farhad Billimoria, Pierluigi Mancarella, and Rahmatallah Poudineh, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics," 2020, https://doi.org/10.26889/9781784671600.

[13] Rebours, Kirschen, and Trotignon, "Fundamental Design Issues in Markets for Ancillary Services."

[14] S R Thorncraft and H R Outhred, "Experience with Market-Based Ancillary Services in the Australian National Electricity Market," *2007 IEEE Power Engineering Society General Meeting, PES*, 2007, https://doi.org/10.1109/PES.2007.385855.

[15] Eric Gimon, "Grid Physics and Markets: A Non-Engineer's Perspective," 2020.

[16] Erik Ela et al., "Alternative Approaches for Incentivizing the Frequency Responsive Reserve Ancillary Service," *Electricity Journal* 25, no. 4 (2012): 88–102, https://doi.org/10.1016/j.tej.2012.04.015.

In the consultation paper, the ESB presented an ESS procurement framework developed by FTI Consulting. The framework consisted of a "progression" of procurement options from 1) directed ESS/self-provision to 2) structured procurement of ESS through contracting, auctions and technical performance standards to 3) procurement of ESS through a spot market mechanism[17]. This framework appears to reflect the ESB's "preference to move toward spot market-based procurement of services"[18].

We find the use of this solution framework problematic as it:

1. Implies that spot markets deliver the most efficient ESS procurement. As outlined above, ESS price formation, cost-allocation and product fungibility pose significant challenges to achieving efficient procurement outcomes in spot markets. Furthermore, additional ESS spot markets will have associated administrative costs and introduce more complexities, particularly with respect to their interface with existing markets in the NEM. It is questionable whether these will be outweighed by their benefits, particularly as specific ESS markets may have limited competition and be subject to exercises of market power[19]. In the NEM, market power and corresponding price spikes have been observed in both regulation[20] and contingency[21] FCAS markets when regional constraints are binding.
2. Implies that the various procurement options are mutually exclusive and that ESS should be marketised if possible. Structured procurement mechanisms are not only helpful in procuring ESS in the context of a transitioning electricity market but may also offer visibility, certainty and potentially immediate control to AEMO. Many power systems, including the NEM, currently procure ESS through a combination of market-based mechanisms and complementary regulatory mechanisms that address market failures or deficiencies[22]. A pertinent example is the implementation of mandatory primary frequency response in the NEM, which aligned the NEM with power systems worldwide in requiring widespread provision of tight-deadband primary frequency response (PFR) through grid codes[23]. We are of the opinion that while some advanced or more costly ESS capabilities should be valued, more basic capabilities could be provided as a condition of access to the power system (as is currently the case with access standards as specified in the National Electricity Rules).
3. Does not consider the effectiveness outcome. Market-based ESS arrangements in the NEM and in many electricity markets globally internalise the opportunity-costs of ESS provision – that is, they remunerate ESS capacity provision[24]. The ESB should place a greater focus on how that capacity might behave or perform within a control context. This will be dictated by the

[17] Energy Security Board, "Post 2025 Market Design Consultation Paper," 61, 72.

[18] Energy Security Board, "Post 2025 Market Design Consultation Paper," 71.

[19] Yann G. Rebours et al., "A Survey of Frequency and Voltage Control Ancillary Services—Part II: Economic Features," *IEEE Transactions on Power Systems* 22, no. 1 (February 2007): 358–66, https://doi.org/10.1109/TPWRS.2006.888965; Guillaume Roger and Behrooz Bahrani, "System Services Rule Changes Consultation Paper Submission - Monash Energy Institute," 2020.

[20] Australian Energy Market Commission, "Frequency Control Frameworks Review," 2018.

[21] Australian Energy Market Operator, "Quarterly Energy Dynamics Q1 2020," 2020.

[22] Ela et al., "Alternative Approaches for Incentivizing the Frequency Responsive Reserve Ancillary Service"; Yann G. Rebours et al., "A Survey of Frequency and Voltage Control Ancillary Services—Part I: Technical Features," *IEEE Transactions on Power Systems* 22, no. 1 (February 2007): 350–57, https://doi.org/10.1109/TPWRS.2006.888963; Rebours et al., "A Survey of Frequency and Voltage Control Ancillary Services—Part II: Economic Features."

[23] Australian Energy Market Operator, "Electricty Rule Change Proposal - Mandatory Primary Frequency Response," 2019; Ciaran Roberts, "Review of International Grid Codes," 2018.

[24] Rebours, Kirschen, and Trotignon, "Fundamental Design Issues in Markets for Ancillary Services"; Christian Hewicker, Alok Kumar, and Musab Arappil, "Dimensioning of Control Reserves in Southern Region Grid States," 2020.

technical and controllable capabilities of power system resources, which includes generators, loads and network elements, as well as the control strategies and systems that are put in place by market participants and AEMO. This is an important consideration as it will clarify the distinction between ESS and highlight interdependencies, interoperability and interchangeability of ESS with similar control functions (discussed further in response to Question 2). Without taking these into account when designing ESS arrangements, this design initiative will fail to address the problems outlined above. An example of a holistic design process that considers both efficiency and effectiveness is the one being undertaken by the EU-SysFlex consortium[25].

e) *Improving existing ESS arrangements*

The ESB has not considered how the existing regulatory environment and energy and FCAS market design could be improved to deliver better operational and investment outcomes prior to introducing additional complexities and costs associated with new markets. We suggest that this be included as a part of the ESB's workplan, given that there is significant operational and investment data and experience that can be drawn on. Potential reforms to existing features related to ESS include fixing the existing 'Causer Pays' cost-allocation framework and considering a 'User Pays' framework, strengthening ESS price formation through demand curves (as proposed in the consultation paper), performance-based incentives/remuneration/enablement and coordinated procurement strategies for locationally specific ESS such as inertia and system strength. We discuss these further in our responses to Questions 1-3.

II. Response to ESB Questions to Stakeholders

1. What feedback do you have on the proposed provision of an operating reserve through spot market provision? … Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?

a) *Short-term resource adequacy – a flexibility product*

The ESB's description of operating reserves "in the context of short term adequacy, including managing uncertainty and variability" over "a number of dispatch intervals"[26] best matches what are known as ramping reserves in North American electricity markets[27]. The California and Midcontinent Independent System Operators (CAISO and MISO, respectively) implemented flexible ramping products within their jurisdictions in 2016. These products are procured based on reliability needs, load and variable renewable energy (VRE) forecasts and historical forecast errors and unit deviations[28].

Procuring such a product in the NEM would assist in meeting large net demand ramps as forecasted by AEMO in its Renewable Integration Study[29]. Furthermore, the introduction of such a product through spot markets co-optimised with existing energy and FCAS markets would make a value for flexibility from resources both explicit and transparent to participants. It is unclear how the costs of

[25] EU-SysFlex, "Product Definition for Innovative System Services," 2019.

[26] Energy Security Board, "Post 2025 Market Design Consultation Paper," 63, 64.

[27] Erik Ela, Michael Milligan, and Brendan Kirby, "Operating Reserves and Variable Generation," 2011, https://doi.org/10.2172/1023095.

[28] E. Ela et al., "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Incentivizing Flexibility in System Operations," *Electricity Journal* 29, no. 4 (2016): 51–60, https://doi.org/10.1016/j.tej.2016.05.001.

[29] Australian Energy Market Operator, "Renewable Integration Study : Stage 1 Report," 2020.

this service would be best allocated, given that its procurement is likely to be driven by AEMO forecasting errors. The risks associated with such a product are that the costs of administering a new market and service outweigh the benefits, and that scarcity pricing in the energy market will be dulled by its introduction into the NEM.

b) *The need for a flexibility product*

It is difficult to conclude whether such a product would be necessary in a post-2025 NEM considering upcoming markets changes and other Market Design Initiatives. Based on their analysis of dispatch-weighted prices received by VRE generators, baseload plant and flexible plant in South Australia, Rai and Nunn concluded that there is an implicit "premium" for generator dispatchability and flexibility[30]. It is likely that such price signals will be sharpened once the five-minute settlement rule change comes into effect in the NEM, though these prices will also be received by inflexible generation dispatched within the same dispatch interval. It should be noted that in the current market design, high prices in the NEM may be the result of either insufficient flexible capability, limited reserve capacity or due to both.

The potential role of demand response in reducing net demand ramps is unclear. Commencement of the wholesale demand response mechanism in 2021, along with other initiatives within the Two-Sided Markets Design Initiative, may provide insight into how demand-side participation can be used to mitigate uncertainty and variability.

Another option is to provide system flexibility through flexible operation of VRE plants. If opportunity-costs are compensated, VRE that is either curtailed ("downward dispatch") or operated with headroom could be called upon to provide system flexibility[31]. This capability, however, requires zero emissions energy to be spilled and can only be provided when the primary energy source of the VRE generator is available.

Ultimately, the need and cost-benefit for a short-term operating reserve or ramping product will be established by market design choices related to longer term Resource Adequacy Mechanisms (RAMs) (Market Design Initiative A) and Scheduling and Ahead Mechanisms (Market Design Initiative D). RAMs such as an enhanced RRO and capacity markets could target generation that is able to offer short-term flexibility, such as the RAM in CAISO[32]. Scheduling processes could use a "look-ahead", multi-period model to assess whether sufficient ramping capability is available within unit commitment timeframes[33]. Such mechanisms could reduce the need for a flexible ramping product.

2. What are your views about developing FFR with FCAS and developing a demand curve for frequency response? Will such a mechanism help manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?

a) *Links between FCAS products*

The interdependencies, interoperability and interchangeability of frequency control services should be well understood before proceeding to consider new FCAS products or design frequency control procurement arrangements. Below, we highlight an example of each:

- **Interdependency:** The slower and centralised control action of regulation FCAS relies on faster and decentralised inertial and primary frequency responses to slow and arrest a

[30] Alan Rai and Oliver Nunn, "Is There a Value for 'Dispatchability' in the NEM? Yes," *Electricity Journal* 33, no. 3 (2020): 106712, https://doi.org/10.1016/j.tej.2020.106712.

[31] Jimmy Nelson et al., "Investigating the Economic Value of Flexible Solar Power Plant Operation," 2018.

[32] Erik Ela et al., "Electricity Markets and Renewables: A Survey of Potential Design Changes and Their Consequences," *IEEE Power and Energy Magazine* 15, no. 6 (November 2017): 70–82, https://doi.org/10.1109/MPE.2017.2730827.

[33] Erik Ela and Mark O'Malley, "Scheduling and Pricing for Expected Ramp Capability in Real-Time Power Markets," *IEEE Transactions on Power Systems* 31, no. 3 (2016): 1681–91, https://doi.org/10.1109/TPWRS.2015.2461535.

change in frequency, respectively[34]. If the latter ESS are insufficient or ineffective, then the former will also be insufficient or ineffective.

- **Interoperability:** This refers to the interfaces or transitions between FCAS. Contingency FCAS arrangements are hierarchical. Fast raise/lower provides a full response within 6 seconds and provides an orderly transition to the slow raise/lower service[35]. Similarly, slow raise/lower provides a full response within 60 seconds and provides an orderly transition to the delayed raise/lower service. Failure to appreciate interoperability may lead to previous or successive control actions being defeated. Should a fast frequency response (FFR) product be incorporated, its interoperability with PFR should be well defined by AEMO.
- **Interchangeability:** FCAS services with similar purposes and that are delivered within similar timeframes may be partially or completely interchangeable. For example, if FFR is sustained and proportional to a frequency deviation, it may be able to substitute conventional PFR[36]. Interchangeability is already present in the NEM as delayed contingency FCAS procurement is co-optimised with the procurement of regulation FCAS[37]. Both respond within a 5-minute timeframe.

Interdependency, interoperability and interchangeability will change with the definition and quantity of FCAS products. We urge the ESB to not only consider procurement mechanisms for frequency control, but to also assess the effectiveness of both current and proposed FCAS products and the NEM's frequency control strategy with AEMO's advice. In other words, the control objective (i.e. frequency control at the nominal frequency) and effective control action should be prioritised when defining fungible FCAS products.

b) Fast frequency response and its purpose

FFR is an umbrella term for frequency response that can be provided within a matter of milliseconds by frequency-responsive relays and IBR. It can be divided into two types of responses. The first mitigates high rate of change of frequency (RoCoF) through processes and control behaviours that are similar to but are not the same as the inertial response of a synchronous generator[38]. This includes inertia-based FFR (otherwise known as "synthetic", "hidden" or "emulated" inertia), which extracts kinetic energy from wind turbine blades to rapidly provide additional electrical energy to the power system following a fall in frequency[39], and 'virtual' inertia, which refers to a control action provided by grid-forming inverters that mimic the inertial response of a synchronous machine[40] . AEMO and the international community have moved towards classifying these inverter control actions as a form of FFR, rather than inertia provision[41].The second

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[34] Joseph H Eto et al., "Frequency Control Requirements for Reliable Interconnection Frequency Response," 2018; Jan Machowski et al., *Power System Dynamics: Stability and Control*, 3rd ed. (John Wiley & Sons, Ltd, 2020).

[35] Jenny Riesz, Joel Gilmore, and Iain MacGill, "Frequency Control Ancillary Service Market Design: Insights from the Australian National Electricity Market," *Electricity Journal* 28, no. 3 (April 2015): 86–99, https://doi.org/10.1016/j.tej.2015.03.006.

[36] NERC Inverter-Based Resource Performance Task Force, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," 2020.

[37] Australian Energy Market Operator, "Constraint Formulation Guidelines," 2010.

[38] Robert Eriksson, Niklas Modig, and Katherine Elkington, "Synthetic Inertia versus Fast Frequency Response: A Definition," *IET Renewable Power Generation* 12, no. 5 (2018): 507–14, https://doi.org/10.1049/iet-rpg.2017.0370.

[39] Nicholas Miller, Debra Lew, and Richard Piwko, "Technology Capabilities for Fast Frequency Response," *GE Energy Consulting*, 2017.

[40] Thomas Ackermann et al., "Paving the Way: A Future Without Inertia Is Closer Than You Think," *IEEE Power and Energy Magazine* 15, no. 6 (November 2017): 61–69, https://doi.org/10.1109/MPE.2017.2729138.

[41] Australian Energy Market Operator, "Fast Frequency Response in the NEM," 2017; Paul Denholm et al., "Inertia and the Power Grid : A Guide Without the Spin," 2020.

type of FFR provides a sustained response through frequency droop control or a step response[42]. This is essentially a more rapid form of conventional PFR.

Following a contingency event, the rapid supply-demand correction offered by FFR can reduce the need for slower frequency response in high inertia power systems and can partially reduce, but not completely replace, the need for operational inertia in low inertia power systems[43]. With AEMO forecasting that inertia levels in the NEM could drop by as much as 35% by 2025[44], there could be a need for FFR to maintain power system security. Multiple FFR services may need to be procured to fulfil multiple purposes (e.g. RoCoF mitigation, sustained FFR, fast regulation FCAS). However, as outlined above, the interdependencies, interoperability and interchangeability between any potential FFR services, existing FCAS services and inertial response should be considered by both the ESB and AEMO.

Given the complex nature of scheduling and dispatching inertia from existing synchronous generation and the interchangeable and flexible nature of FFR, it may be preferable to procure FFR to reduce regional or global requirements for inertia (discussed further in our response to Question 3).

c) Managing uncertainty and improving power system resilience

One of the options being considered by the ESB includes "exploring options to define demand curves for frequency control, allowing the valuation of the provision of frequency response beyond minimum levels to support greater resilience"[45]. Compulsory provision of certain FCAS capabilities through regulatory mechanisms, such as mandatory PFR, reduces uncertainty for AEMO and improves power system resilience to a greater extent without the additional complexities of determining appropriate demand curves and the costs associated with administering additional markets. So long as the opportunity-costs of reserved headroom are valued, mandatory PFR provision may be more effective and robust than transitioning to a market-based mechanism.

d) Additional mechanisms

As outlined in Section I, we believe that current FCAS market arrangements can be modified to improve the effectiveness and productive and dynamic efficiency of frequency control in the NEM. These improvements include:

- **Improving cost-allocation processes for FCAS markets**. This could provide suitable disincentives for undesirable behaviour ("Causer Pays") or allocate costs to users that impose frequency deviation limits or RoCoF limits on the power system ("User Pays). Efficient cost-allocation could also create counter-parties for hedging FCAS price risk and therefore assist in FCAS price formation[46]. Current "Causer Pays" arrangements in the NEM are inefficient. Regulation FCAS contribution factors are calculated using a complex methodology and are averaged over a 5-minute dispatch interval, summed over a 28-day period and then summed over a market participant's portfolio, resulting in a blunt and

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[42] Pieter Tielens and Dirk Van Hertem, "Grid Inertia and Frequency Control in Power Systems with High Penetration of Renewables," 2012; Ana Fernández-Guillamón et al., "Power Systems with High Renewable Energy Sources: A Review of Inertia and Frequency Control Strategies over Time," *Renewable and Sustainable Energy Reviews* 115, no. August (2019): 109369, https://doi.org/10.1016/j.rser.2019.109369; NERC Inverter-Based Resource Performance Task Force, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs."

[43] Australian Energy Market Operator, "Fast Frequency Response in the NEM"; Australian Energy Market Operator, "Inertia Requirements Methodology: Inertia Requirements & Shortfalls," 2018; NERC Inverter-Based Resource Performance Task Force, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs."

[44] Australian Energy Market Operator, "Renewable Integration Study : Stage 1 Report."

[45] Energy Security Board, "Post 2025 Market Design Consultation Paper," 66.

[46] Thorncraft and Outhred, "Experience with Market-Based Ancillary Services in the Australian National Electricity Market."

misunderstood price signal[47]. However, an appropriate balance or methodology will need to be established as sharper price signals may lead to market participants curtailing or recommitting units to avoid exposure to costs. This has been observed in the NEM when regional constraints have led to FCAS price spikes[48].

- **Strengthening FCAS price formation.** This could be achieved through a system demand curve as proposed by the ESB. The success of this measure will depend largely on the shape of the demand curves. Demand curves could reflect reliability (e.g. Loss of Load Probability, which is used in markets in North America[49]), contingency events and for some FCAS such a regulation, measures of system variability and uncertainty (e.g. Forecast Uncertainty Measure). Incorporating some of these may require a "dynamic" demand curve that expresses the system's preferences for FCAS based on power system conditions. However, it is unclear how FCAS system demand curves will account for FCAS interdependency and interchangeability.
- **Aligning remuneration with FCAS performance.** Performance-based remuneration may overcome some of the issues associated with fungibility in ESS markets by incentivising higher quality provision. This, in turn, may potentially reduce procurement requirements and improve the efficiency of FCAS procurement. Examples of performance-based remuneration in FCAS markets include regulation services in the PJM Interconnection, where each part of a unit's offer and its remuneration is adjusted by its performance score[50], and the FFR service in the UK, where remuneration may be penalised or withdrawn due to poor performance[51]. A spectrum of frequency control performance has been observed in the NEM. For example, high quality regulation FCAS from battery energy storage systems has been remunerated at the same price as oscillatory and relatively inaccurate control action from thermal generation[52].

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[47] Australian Energy Market Operator, "Regulation FCAS Contribution Factor Procedure," 2018; Australian Energy Market Commission, "Frequency Control Frameworks Review"; Australian Energy Regulator, "Issues Paper - Semi Scheduled Generator Rule Change(S)," 2020; DIgSILENT, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions Final Report," 2017.

[48] Australian Energy Market Operator, "Quarterly Energy Dynamics Q1 2020."

[49] William W. Hogan, "Electricity Scarcity Pricing through Operating Reserves," *Economics of Energy and Environmental Policy* 2, no. 2 (2013): 65–86, https://doi.org/10.5547/2160-5890.2.2.4; Peter Cramton, "Electricity Market Design," *Oxford Review of Economic Policy* 33, no. 4 (2017): 589–612, https://doi.org/10.1093/oxrep/grx041.

[50] Adria E. Brooks and Bernard C. Lesieutre, "A Review of Frequency Regulation Markets in Three U.S. ISO/RTOs," *Electricity Journal* 32, no. 10 (2019): 106668, https://doi.org/10.1016/j.tej.2019.106668.

[51] Daniel Fernández-Muñoz et al., "Fast Frequency Control Ancillary Services: An International Review," *Renewable and Sustainable Energy Reviews* 120, no. December 2019 (2020), https://doi.org/10.1016/j.rser.2019.109662.

[52] Australian Energy Market Operator, "Initial Operation of the Hornsdale Power Reserve Battery Energy Storage System," 2018.

3. What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, and what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?

a) *'Physical' inertia and FFR*

We suggest that the ESB revisit the grouping of 'synthetic' and 'physical' inertia. A 'physical' inertial response is an instantaneous and inherent electromechanical response provided by synchronous machines following a frequency deviation in the power system[53]. What distinguishes FFR such as 'virtual' and 'synthetic' inertia from 'physical' inertia is that the former two require some form of measurement and are not inherently provided by IBR but, unlike 'physical' inertia, are tuneable control responses. While these inverter control actions cannot altogether replace and may rely on the provision of a minimum level of 'physical' inertia, they can be used to reduce 'physical' inertia requirements (as is currently the case if an inertia shortfall is declared)[54].

b) *An independent procurement mechanism for inertia*

Much like other ESS, it is important to consider how 'physical' inertia might be provided in the NEM and its linkages with other ESS and energy. 'Physical' inertia is provided by synchronous machines with rotating masses[55]. In the case of synchronous generators and loads, inertia is supplied along with the generation and consumption of active power, respectively. Due to the larger physical masses and higher rotational speeds of synchronous generators, provision of 'physical' inertia by loads is often relatively small and ignored.[56]. For these resources, the provision of inertia is linked with the generation or consumption of active power.

Another type of resource that can provide 'physical' inertia are synchronous condensers, which include synchronous generation retrofitted with synchronous condensing clutches. Synchronous condensers can provide inertia and reactive power support at the expense of a small parasitic active power load[57]. As such, these resources can provide inertia that is effectively independent of their active power contribution to the power system.

Given that synchronous condenser technology is proven and that the provision of 'physical' inertia does not come at the cost of providing other active power services such as energy and FCAS, we are of the view that the ESB should deliver a procurement mechanism for inertia that is not intertwined with energy market outcomes in the longer-term. One procurement option for the ESB to consider is a transparent and competitive structured procurement mechanism. This may allow providers to express the costs at which they would be able to provide inertia whilst minimising distortions to the energy market. Such a mechanism does not preclude the use of a system demand curve, which could provide a stronger investment price signal and enable AEMO to procure additional inertia when efficient to do so.

A spot-market mechanism for inertia may introduce the following problems:

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[53] Machowski et al., *Power System Dynamics: Stability and Control*.

[54] Australian Energy Market Operator, "Inertia Requirements Methodology: Inertia Requirements & Shortfalls."

[55] Machowski et al., *Power System Dynamics: Stability and Control*.

[56] Denholm et al., "Inertia and the Power Grid : A Guide Without the Spin."

[57] Huajie Gu et al., "Review of System Strength and Inertia Requirements for the National Electricity Market of Australia," *CSEE Journal of Power and Energy Systems* 5, no. 3 (2019): 295–306, https://doi.org/10.17775/cseejpes.2019.00230.

- Commitment of generators out of the energy market merit order may occur if regional minimum inertia requirements need to be met. This outcome is not limited to directions by AEMO and may occur as a result of Unit Commitment for Security or as an outcome of ESS ahead markets that are required to procure a minimum quantity of inertia (Market Design Initiative D). While the provision of inertia is valued in both circumstances (albeit in very different ways), the commitment of such generators may still distort prices in the energy market and affect operational and investment price signals in unintended ways[58]. This issue is particularly pertinent in South Australia, where most synchronous generation is typically higher in the merit order stack.
- Regardless of the merit order of unit commitment and dispatch, an inertia spot market may be subject to exercises of market power. It is plausible that in a NEM region in the future, a limited number of synchronous generators may be brought online during a commitment period (depending on which, if any, ahead mechanism is implemented). This problem may be exacerbated by the 'lumpy' nature of inertia provision - suppliers may have a greater influence over the market supply curve than suppliers of 'continuous' commodities such as energy.

However, we acknowledge in the short term that sufficient levels of 'physical' inertia may require units to be committed out of merit order. To minimise this and any distortions to the energy market, the ESB and AEMO could prioritise the procurement of FFR to reduce operational inertia requirements for regions in the NEM.

c) "Active" and "passive" voltage management

Voltages at nodes in the power system is managed through the production or absorption of reactive power by generators, loads and network elements[59]. We consider this to be an "active" form of voltage management, as a measurable commodity (reactive power) is being produced or absorbed.

There are also what we will refer to as "passive" forms of voltage management. This includes network configuration and system strength, the latter of which is both[60]:

a. The ability of the power system to maintain a stable voltage waveform, during both normal operation and following any change in the system.
b. A quality related to the electrical interactions between different components of the power system.

The provision of system strength includes grid forming capabilities, appropriate control system tuning and protection system configuration and the provision of sufficient fault current from power system resources. These are properties or capabilities of power system resources rather than a measurable commodity. As such, system strength can be classified as a "passive" form of voltage management.

d) The need for coordination

Given that system strength is defined by "passive" interactions and that system strength and voltage issues are highly locationally dependent, efficient "procurement" requires co-ordination between market participants, AEMO and network service providers. We see spot markets and

[58] Huajie Gu et al., "Zonal Inertia Constrained Generator Dispatch Considering Load Frequency Relief," *IEEE Transactions on Power Systems* 35, no. 4 (2020): 3065–77, https://doi.org/10.1109/TPWRS.2020.2963914.

[59] Australian Energy Market Operator, "Power System Requirements," 2020.

[60] Australian Energy Market Commission, "System Services Rule Changes - Consultation Paper."

competitive procurement strategies as inappropriate for managing system strength as there is no fungible commodity and because managing interactions requires co-ordination and collaboration.

The "Efficient management of system strength on the power system" rule change proposed by TransGrid proposes a suitable mix of NSP provision and access standards for addressing system strength requirements[61]. This proposal enables Transmission Network Service Providers to co-ordinate services to meet system strength planning standards set by an independent body. While generator performance standards would still need to be negotiated for a generator to connect to the power system, a connecting party would not be required to "do no harm", thereby reducing the barriers to connection and enabling the TNSP to decide how best to meet the required planning standards. While we support this mechanism, we suggest that the AEMC, ESB and TNSPs consider how costs for a particular node under this mechanism may be allocated to future entrants that benefit from system strength remediation[62].

4. Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?

a) Prioritising objectives

As succinctly put by Rebours et al., "markets for electrical energy cannot function if the underlying power system does not operate securely"[63]. When considering ESS, there is a strong justification for giving AEMO and TNSPs significant regulatory flexibility. Regulatory mechanisms can provide certainty to AEMO that it will meet power system operating standards and can improve power system resilience if widespread provision of ESS is made compulsory. We also support the ESB's proposal to continue trials for AEMO and market participants to gain practical experience with new approaches.

There is, of course, a concern related to the cost of such flexibility and of ESS procurement. AEMO is required to meet power system operating standards and is not immediately incentivised to reduce system costs. Prioritising appropriate and efficient cost-allocation mechanisms for ESS could assist in allocating these costs. Where cost-allocation is not appropriate (e.g. the costs associated with running trials), costs could be socialised to avoid innovative parties being penalised by first-mover disadvantages.

b) Rapid feedback and assessment

We suggest that increased regulatory flexibility for AEMO and TNSPs be accompanied by more rapid feedback and assessment of new measures and mechanisms. Such assessment has typically been slow in the NEM. For example, frequency control in the NEM has deteriorated over several years, but it was only this year in which a mechanism for procuring tight-deadband primary frequency response was implemented[64]. In addition, socialised costs that are incurred as a part of trials, etc., should also be subject to oversight. While this could fall under the purview of the AER, we suggest that the ESB consider who might be best placed to assess and provide oversight of the NEM's ESS effectiveness and efficiency.

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[61] Australian Energy Market Commission, ERC0300.

[62] Billimoria, Mancarella, and Poudineh, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics."

[63] Rebours, Kirschen, and Trotignon, "Fundamental Design Issues in Markets for Ancillary Services."

[64] Australian Energy Market Commission, "Mandatory Primary Frequency Response, Rule Determination," 2020.

III. Parallel market design processes

We welcome the ESB's approach to consulting with stakeholders across all aspects of the Post-2025 Market Design Process. This enables the linkages between technical considerations and market and regulatory mechanisms to be considered and assessed together. Market design is a complex process, and a "systems-thinking" approach is preferable, if not necessary.

In this light, we find it concerning that mechanisms considered within the Essential Systems Services are also being considered by the AEMC as a part of the "System services rule changes"[65]. With the exception of TransGrid's proposed rule, all other rule changes being considered are proposing new ESS products or markets. Considering such mechanisms within the scope of the rule change process is inappropriate as:

1. The need for a product or market cannot be assessed against other design options.
2. The product or procurement mechanism is assessed as proposed. Proposals often reflect the interests of the proponents (who, except for TransGrid, are all market participants) and may not be the best product definition or procurement mechanism.

However, if AEMO establishes that there is a clear need for a service or if a proposal offers several benefits, it may be preferable for these to be considered in greater detail within a specific rule change proposal (as suggested by the AEMC). We anticipate that this may be the case for TransGrid's "Efficient management of system strength on the power system" proposal and Infigen Energy's "Fast frequency response market ancillary service".

[65] Australian Energy Market Commission, "System Services Rule Changes - Consultation Paper."

D. Scheduling and Ahead Mechanisms

One of the consequences of the transitions occurring in the NEM is the changing nature and timeframes of power system uncertainties. With growing penetrations of variable renewable energy capacity, markets need to be flexible and 'fast' to better respond to more accurate real-time information, such as short-term wind, solar and load forecasts[66]. However, this approach can be at odds with the relative inflexibility of conventional plant which have restricted operating envelopes defined by minimum operating levels and start-up and shut-down times and costs. In a transitioning power system, there is a trade-off between 'operational' flexibility, which is typically constrained by large conventional thermal plant, and increased accuracy and market 'flexibility' that enable the efficient dispatch of variable renewable energy, inverter-based resources and other flexible technologies such as demand response (see Figure 2).

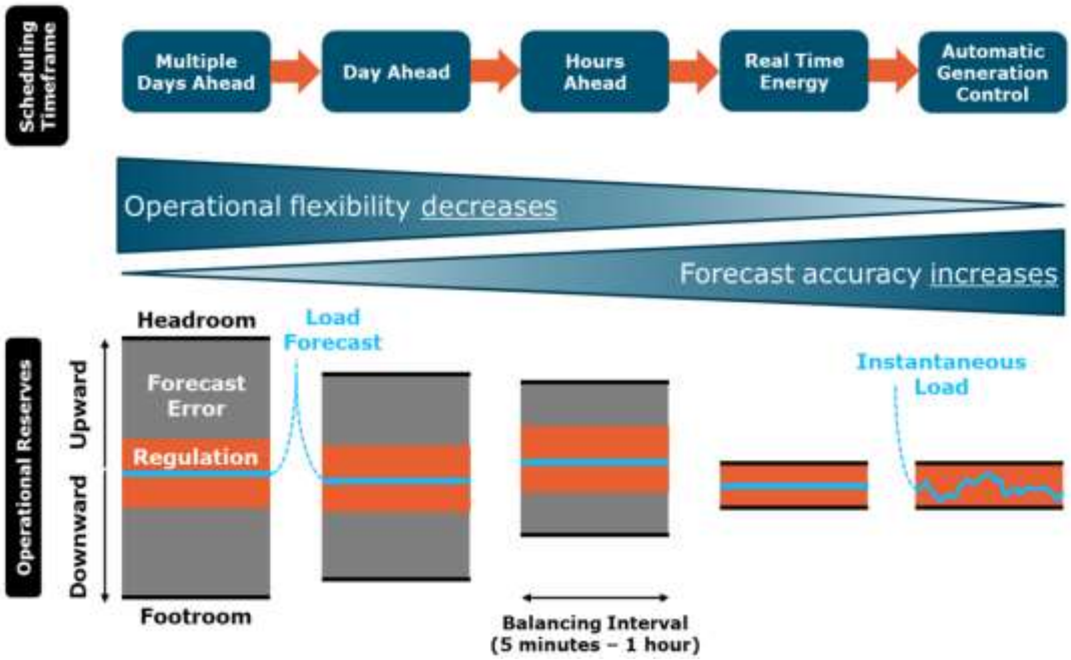

Figure 2: Scheduling, uncertainty and flexibility over various timeframes in a transitioning power system [67].

1. The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?

We generally support the ESB's option of a Unit Commitment for Security (UCS) process. A UCS tool could provide a more holistic, thorough and transparent assessment of power system requirements when compared to the current directions process. The process also facilitates unit commitment where ESS are procured via contract by AEMO and NSPs.

However, in our opinion, the consultation paper does not establish a particularly strong case for implementing any of the ahead markets. The need for a system service ahead market is entirely dependent on how ESS are defined and procured (discussed in further detail within MDI-C). While such a platform could facilitate short-term contracting, the implementation of look-ahead 'dynamic' demand

[66] Jenny Riesz and Michael Milligan, "Designing Electricity Markets for a High Penetration of Variable Renewables," *Wiley Interdisciplinary Reviews: Energy and Environment* 4, no. 3 (2015): 279–89, https://doi.org/10.1002/wene.137.

[67] Nelson et al., "Investigating the Economic Value of Flexible Solar Power Plant Operation."

curves and enable providers to hedge ESS provision risk, we do not see how the introduction of an additional market and the complexities and costs associated with it would be of benefit for services that are co-optimised with real-time energy dispatch. Should uncertainty of provision be an issue for AEMO, then a spot-market procurement mechanism may not be appropriate in the first place (see discussion in MDI-C section). Furthermore, we see a financially binding set of arrangements as inappropriate as, unlike energy provision, deviation from a schedule for ESS provision cannot be mitigated by ESS 'reserves'.

Financially or physically binding ahead markets would enable energy and ESS co-optimisation but largely favour conventional thermal plant and their limited operating envelopes. The implementation of such ahead markets may weaken real-time market signals for flexibility (as stated above, this will depend on if and how an operating reserve product is implemented) and prolong the operation of unreliable and carbon-intensive generation. As suggested by the ESB, N ahead market could serve as a broad and transparent short-term risk management platform for market participants across both energy and ESS. The benefits of such a platform need to be considered against the function of the existing derivatives market and complexity of mechanisms that would enable price convergence between ahead and real-time markets (e.g. virtual bidding[67]). The latter is somewhat of an issue in existing arrangements given that there is a growing variance between pre-dispatch price forecasts and actual spot market prices.

2. The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?

We support the development of the UCS as a decision support tool. As outlined by the ESB, we see such a tool providing a systematic methodology for assessment, along with greater transparency and the potential to optimise decisions that are made to support system security.

We suggest that a UCS tool should be probabilistic in its design, given increasing levels of power system uncertainty and variability[68]. A probabilistic assessment tool could capture a wider range of faults and failure modes and be used in conjunction with probabilistic or duration-based reliability and security standards, such as the existing Reliability Standard and the interim Unserved Energy standard. Forecast uncertainty, unit reliability and risk of interconnector faults are some of the probabilistic measure that could be incorporated into a UCS tool. However, we acknowledge that there is a trade-off between the accuracy and computational intensity of modelling complex power system phenomena[69] and the need for rapid and frequent assessment. AEMO may need to conduct preliminary analysis, seek experience from other system operators and consult with stakeholders to determine a modelling methodology that is suitable and tractable.

We also see the need for the greater transparency offered by a UCS tool to drive necessary market rule changes and infrastructure assessment. The ESB and AEMO should consult with market participants and other market bodies to determine an appropriate reporting format and platform to facilitate improvements.

E. Two-Sided Markets

As the Consultation Paper notes, there is significant cross-over between the workstream on 2-sided markets and that on DER integration. We support the proposal to seek to bring these two workstreams together given that both represent and require greater energy user engagement with the market. A particular challenge for the NEM is the relatively dysfunctional nature of present retail market design and structure in the NEM, from the poor transparency of market operation (e.g. how many customers are on what tariffs), limited metering with many small energy users still on accumulation meters, competition largely defined in terms of commodity kWh pricing rather than on the delivery of the energy services that consumers actually want, through to the present market dominance of a small number of vertically integrated retailers.

1. What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?

There are always risks associated with unintended consequences of market changes. We agree with the Consultation Paper that greater energy user engagement is near inevitable. A key question is whether such engagement will be conducted within formal market arrangements, or focus instead on responding to wholesale or retail market signals. Certainly, high demand-side participation outside formal market dispatch poses significant risks to orderly and efficient dispatch outcomes.

There are also risks in not facilitating greater energy user participation given what look to be many highly cost-effective opportunities to improve system flexibility, and hence assist in renewable energy integration.

2. What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?

The barriers are many. However, one that doesn't receive sufficient attention in the Consultation Paper would seem to be that there are potentially significant advantages for energy users to avoid participating in central dispatch processes whilst still responding to the resulting market signals (wholesale and/or retail). Some level of compulsion seems likely to be required, although this will need to managed with considerable care.

3. Do you think any other near term arrangements or changes to the market design can be explored in this workstream?

One opportunity that seems to be missing from present discussions is how market design changes might facilitate the development of new market players focussed on assisting energy users to achieve their energy service needs and desires at least cost. Such assistance might well involve support for implementing energy efficiency options. These are the missing players in present market arrangements.

4. What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?

As usual, some combination of 'carrots and sticks' is likely to be required. 'Carrots' are likely the key driver to support early adopters.

F. Valuing Demand Flexibility and DER Integration

As the Consultation Paper notes, DERs represent perhaps the greatest challenge for future NEM market design. They are deployed by energy users with often only a passing interest in the electricity industry beyond secure affordable energy services and are irrelevant to system outcomes at an individual level but potentially enormously impactful at aggregated scale. Importantly, they 'reside' within the NEM's currently dysfunctional retail market arrangements - arrangements which don't encourage socially beneficial operation and investment decision making in many cases.

We agree on the importance of the five 'considerations' noted in the Consultation Paper. The issue of whether DER services are best delivered through off-market or market processes are particularly vexed. There are good reasons to focus on regulatory and technical requirements initially, and these may be able to deliver much of the benefits available with market incentives. However, this may result in adverse equity outcomes - for example, if large market participants get paid to provide services that DERs are required to supply for free.

The question of how much responsive DER and how many willing DER owners there may be is also a key uncertainty. Investor certainty gets a lot of discussion at the utility scale but remarkably little at the DER level. DER investors would also like greater investment certainty, and face significant risks from changes such as revised, supposedly more 'cost reflective' network tariffs and potential network constraints. Infrastructure requirements and reasonable administrative and other costs for participation are also relevant, as is the balance between participation and full market integration of DER. As such, we support further ESB work addressing all these five considerations.

G. Transmission Access and the Coordination of Generation and Transmission

We are agreed that transmission investment has a key role to play in a secure clean energy transition for the NEM, and that current access and pricing arrangements may not incentive the most efficient investment in terms of renewable project locations. However, existing projects, those under construction and those committed represent sunk costs, suggesting that a key challenge is to strengthen the network to facilitate their market participation. While it is possible to improve the efficiency of market 'signals' for new projects, our concern is that the work underway may adversely impact on overall NEM effectiveness and efficiency under transition. We note the work by the Clean Energy Council and others highlighting the uncertainty and hence potential delay that the CoGaTI process is creating for renewable project developers. As noted in the introduction, in interconnected markets with a range of inefficiencies, the principle of sub-optimisation holds that "optimizing each subsystem independently will not in general lead to a system optimum, or more strongly, improvement of a particular subsystem may actually worsen the overall system."

Time is money, as is risk. We are unclear that modelling undertaken by CoGaTI properly factors in the costs of delay and uncertainty imposed by CoGaTI on total NEM costs over the longer term. A further problem here is that the current NEM doesn't price key externalities such as the adverse impacts of climate change. As a simple thought experiment, if CoGaTI was to delay 2GW of renewable generation for two years, and emissions were priced at a social cost of \$90/tCO2, then the CoGaTI process would impose a carbon cost approaching A\$1 billion on the NEM.[68] In the absence of economically efficient carbon pricing or equivalent policy measures for the NEM, we believe that the ESB should 'shadow' price carbon into their market design processes to minimise such 'sub-optimisation' risks.

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[68] MacGill, I (2019) "An end to end approach for market design that integrates utility generation and transmission, variable renewables and a rapidly evolving distribution network with distributed energy resources" Presentation at the *IEA/ESB Future Electricity Market Summit,* Sydney, November 2019. Available at www.ceem.unsw.edu.au

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