SUBMISSION

ESB POST 2025 MARKET DESIGN CONSULTATION PAPER
19 OCTOBER 2020

INTRODUCTION

The Energy Users Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

Much of Australian manufacturing industry has been built on the availability of internationally competitive and reliable electricity supply. This international competitiveness has been severely challenged in recent years due to a range of factors including rising gas and coal prices, the sometimes chaotic transformation of energy markets and climate policy uncertainty. During this period of great change it is clear that technology and climate concerns are driving a rapid transition of energy markets to a totally different generation mix. Accompanying this, consumer involvement in energy markets through the installation and use of technologies such as roof-top solar, batteries and electric vehicles creates both opportunities and issues that must be carefully managed.

All too often we see the negative consequences of these changes having a significant and immediate impact on large commercial and industrial customers as costs and risks are disproportionally passed through to them. For example, the increasing costs of interventions by the market operator are passed directly through to commercial and industrial energy users, usually within weeks of being incurred while the requirement to engage in under frequency load shedding creates risks that can't be managed and losses that won't be compensated.

It is for all of these reasons that we consider one of the key objectives of the current ESB review should be to ensure Australian industry regains an internationally competitive electricity supply position and that future costs and risks are spread more equitably across the many energy industry stakeholders.

Historically, market design has tended to be the responsibility of Governments, regulators and the supply side. Consumers are meant to take comfort from the National Electricity Objective (NEO) but, in our view, that has tended to be seen through the lens of market participants and governments rather than consumers themselves.

Therefore, it is heartening to see that consumers are having a greater voice, although this is a "work in progress" while technology is giving them greater choice as to where and how they source their electricity. Consumers are now active participants in energy markets, giving them more market power than before and are more able to express their own views more directly rather than being filtered through other players. While consumers are sometimes a broad church, we generally align on most key issues – being the need for a reliable, efficient and competitive supply.

At the outset we wish to congratulate the ESB on the comprehensive and professional approach it has taken to assessing and engaging on the post 2025 market design. We particularly note the inclusive approach taken to engaging with our members.

Large electricity users will always have their day job in producing their particular products and have limited time for detailed involvement in supply side market reform. The ESB has recognised that and appropriately tailored the engagement program to give our members maximum opportunity to contribute.

Our response to the Consultation Paper is in three parts:

(i) The form of what we think the ESB should produce in its next report in December/January to enable stakeholders to provide the required detailed comments
(ii) General principles that should guide consideration of particular policy choices, and
(iii) Specific comments on Market Design Initiatives

We are faced with somewhat of a chicken and egg dilemma when considering the specific questions asked for each MDI. But we recognise the ESB is in a somewhat similar situation. It can be difficult for us to give a definitive answer to a question "should option x be considered further?" when we are not provided with a full understanding of the costs and benefits of option x vs option y or whether x or y are better when combined with z (recognising the limitations of modelling). Yet we understand the ESB cannot examine every option in great detail and needs stakeholder guidance on what options to pursue in greater depth. The design paper and associated consultants' reports have helped considerably in framing our response as has where the ESB has identified approaches that they are not proposing to pursue any further.

To help the ESB understand our starting position on the issues raised and the general direction we think the analysis should proceed, we have set out what we consider are key guiding principles for how the post 2025 market should be designed. This has informed our choices of specific approaches where we would support further ESB analysis and why we agree with not pursuing particular options. Where we have not made specific choices, the principles should indicate the general direction we would recommend the ESB take.

We look forward to continued engagement with the ESB as they refine their recommendations to Ministers.

WHAT SHOULD THE ESB PRODUCE IN DECEMBER 2020/JANUARY 2021

The options outlined are variants on 'NEM evolving' and not a 'big bang'

The discussion on Next Steps on p.12 says:

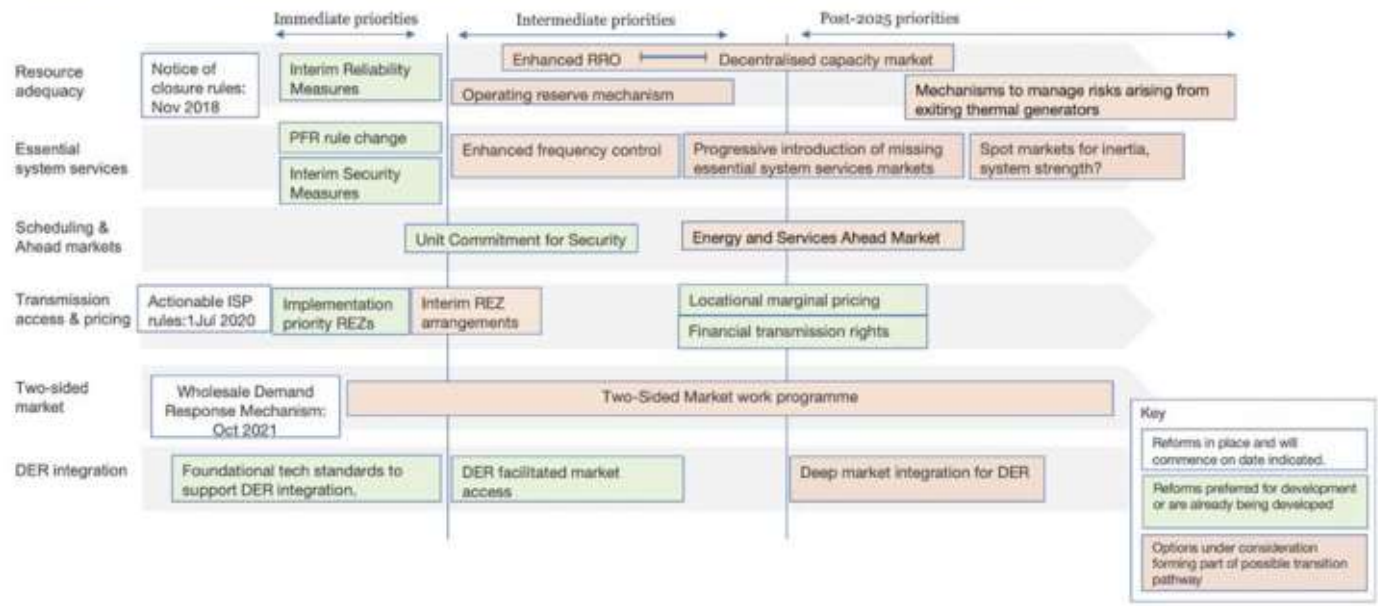
> *"The next phase is to evaluate potential solutions. Option(s) for future market design will be developed over this period with input from stakeholders, with design options released for consultation around late December 2020 or early 2021.*

The ESB will provide advice to Energy Ministers on changes to the existing market design, or recommend an alternative market design, to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost by mid-2021"

We are pleased to see that the ESB has moved beyond the original intention of presenting three options in December/January, one of which could be described as "NEM evolving" and each option a discreet package drawing on each workstream. Maintaining a level of flexibility along each workstream at this point is preferable with further refinement to come in coming months as more detailed analysis is undertaken.

We are particularly pleased to see that there will be no 'big bang' in 2025 as we do not believe the NEM is broken and significant upheaval is both unnecessary and has too many risks to all stakeholders. We concur with the view that moving forward will involve an evolution of the current market design. This suggests what is presented at the next stage would draw on the sort of phased market development in Figure 1 (p11):

FIGURE 1 PHASED MARKET DEVELOPMENT – A REPRESENTATIVE EXAMPLE



With the rejection of a centralised capacity market (which we agree with as per comment on below), it seems that the preferred overall framework is "NEM evolve" with the options presented reflecting different ways of implementing the objectives in the green and pink boxes above e.g. the what (role of centralised direction vs market provision in a rules framework) and the when (quick vs slow implementation) and what are complementary measures.

Market body and formal rule changes up to mid-2021 should be consistent with any post 2025 model

Given this 'evolution' approach, we would like the December/January report to give us confidence that any changes proposed by AEMO/AER/AEMC/ESB:

- that are still under consideration at that time, are consistent with any of the three models recommended for further consideration, and

- models that will be considered in the first half of 2021 will have a section in the stakeholder consultation documentation setting out how they are consistent with any of the three options then under consideration.

At present we have difficulty with the implicit assumption that this will be achieved given the fluctuating environment we find ourselves in. For example, in our recent submission on a package of six rule changes around systems services, it was difficult to comment on them without having more context of the preferred post 2025 model.

We concluded[1]:

> *"If at the completion of the broader post 2025 work program any of these rule changes are deemed necessary, we expect that a more complete package of reforms is presented to consumers that includes independently verified cost benefit analysis and a framework for more appropriate cost and risk allocation."*

We understand that there will inevitably be urgent matters that need to be dealt with prior to mid-2021 but we need to achieve a high level of confidence from the relevant market body that the proposed changes are required at that time and are consistent with whatever model Ministers select in mid 2021. We are sure all stakeholders would agree that with limited resources we want to have confidence we are not wasting time on developing submissions on issues that are not aligned with the overall 2025 model.

The Paper notes (p.26):

> "Some MDIs are more progressed than others, and some parts of a design have been more considered. The transmission access and coordination of generation and transmission investment MDI is a good example, because the AEMC has progressed work on this matter for some time. It is also the case that some parts of an MDI are likely to be progressed and implemented earlier than 2025. Elements of the scheduling and ahead mechanisms and essential systems services workstreams are both initiatives in this category."

Which will influence the what and the when that is presented to Ministers.

We see a roadmap for implementation

We look forward to the presentation of the different 'NEM evolve' models in December/January which should be part of a detailed roadmap that also includes:

- Detailed schedule for implementation and sequencing of reforms
- The merits of the individual measures against evaluation criteria outlined in the Appendix
- What additional options analysis that is to be undertaken in the first half of 2021 to assist in selecting the preferred model
- Risk analysis
- Specification of what success looks like and how it is to be measured.

[1] See https://euaa.com.au/euaa-submission-system-services-rule-changes/

GUIDING PRINCIPLES

Efficiently utilises Australia's world class electricity resources to our competitive advantage

Australia's world competitive energy intensive industries have reached that position in the past because of internationally competitive power supply. In the future they will regain that position based on secure, reliable and competitive low emissions electricity and a recognition of the role large users can play in both providing stable demand and a range of services to assist system stability and reliability.

We support the ESB's rejection of a centralised capacity market

We do not think the NEM is broken and therefore do not see a case for fundamental change of the market design to a centralised capacity market. This approach involves a fundamental shift in risk allocation to consumers that we do not accept as the best way of achieving the NEO. It removes the role of the market to innovate and find new and more efficient ways to achieve the NEO. Evidence from markets where a centralised capacity market operates does not support it being superior to a decentralised market in achieving the NEO.

We support a 'liberalised' market as the core of the NEM

The EUAA's view is to favour continuation of a predominately 'liberalised' market with incremental change. This is achieved through the creation of the rules framework that provides the maximum opportunity for efficient markets to develop and prosper and create the revenue streams to make them 'investable'. Within this framework, scarcity pricing continues to play a central role.

The ability to lodge rule changes provide opportunities for new markets and revenue streams to be developed in the market rather than by centralised regulation and provision. Investors make their decisions on the basis of views on future revenue flows, market signals and certainty of policy and regulatory frameworks.

To the extent that the market mechanisms do not provide this level of certainty then some limited centralised measures may be required. However, these measures should not seek to remove risk e.g. those listed in Table 2 p.32, because removing it for one party simply moves it to another – usually consumers who are unable to manage it. We agree with the Paper's comment:

> *"The market design needs to change to ensure there are enduring price signals that can drive investment in all the services needed for a reliable and secure supply to strengthen signals for investment, as well as a real-time price that better reflects the cost of providing all services needed for resource adequacy in operational timeframes. We also need to consider what additional assurances or backstops might be needed to support reliability and security if the market does not deliver within operating standards." (p.21)*

For the avoidance of doubt, we need to ensure that the descriptor of a 'decentralised capacity market' is succinct as a more open descriptor can cover a broad church and be subject to interpretation. It is important that the descriptor must lead us closer to a market-based framework than a decentralised capacity market which is unlikely to be not much different to a fully centralised framework.

The focus needs to be on market-based design changes implemented over time that reduces the risk to consumers of lots of changes happening concurrently.

The market design should be robust enough to cope with Government intervention

We recognise that achieving this would be no small feat. To maximise the likelihood of this requires a robust design that is not too complicated e.g. without complex measures that might be great in the purist eyes but opaque in their implementation and impact and sufficiently flexible to cope with the inevitable intervention. We can only hope that any future intervention will be more judicious and measured than has historically been the case, given Energy Ministers will sign-off on the final design.

The design should be a NEM wide design

The Consultation Paper notes suggestions that the market design should take account of different jurisdictional preferences. We strongly oppose this approach. We have recently seen the potential impact of different reliability standards across jurisdictions with the Victorian Government push to modify the reliability standard. It could not be applied just to Victoria and hence other States had to adopt it whether they wanted it or not. Our members support the current 0.002% USE standard and the process through the Reliability Panel to set that standard.

We are in an interconnected, national, electricity market. Multiple standards spell inefficiency and cost to consumers.

We also seek to ensure that consumers are not effectively paying twice for a jurisdictional scheme (e.g. guaranteed strike prices for State Government renewable contracts) as well as a NEM RAMs.

Risk should sit with the party best able to manage it

There has been a lot of debate indicating potential concerns regarding the ability of the supply side to fund the required investment for the energy transition. The supply side is a mix of both government and privately owned parties. Recent policy announcements by Federal and State Governments on proposals to fund or facilitate (e.g. through PPAs) the funding of new generation and network seems to suggest there is no funding constraint for a major part of that transition expenditure.

The Paper notes (p.12) that:

> *"If private sector balance sheets are to fund this significant new investment at least cost, then there will need to be a degree of confidence over future prices and the role of government in the market."*

Often this is interpreted by the private sector as an excuse to push risk onto consumers so as to increase their risk adjusted returns. We saw this in the debate last year on marginal loss factors when renewables investors sought to have consumers accept investing generator location risk when consumers had no influence on where renewable generation was built.

It was argued that smoothing the marginal price signal would potentially lower the cost of capital and that was supposed to be great news for consumers because it would result in lower power prices. Yet all the renewable generators' proposal did was to move risk from one part of the chain that had the ability and incentive to manage it, to consumers who had an incentive but no ability to mitigate any negative impact.

As the AEC argued in its submission on the matter[2]:

> *"Ad absurdum this cost of capital argument suggests investors should never be exposed to market signals as risk-free capital is always cheapest. Marginal loss pricing has been a feature of the NEM since its inception. A sudden change to the arrangements would substantially shift the competitive deckchairs, with those who have invested with greatest attention to losses disadvantaged. The NEM's reputation regarding stability of rules would be harmed, in fact increasing investment risk in exactly the opposite way intended."*

We caution against too much focus on a conservative view of what an 'investable' market means. There will always be uncertainty and 'investable' does not mean investors are guaranteed a certain return. Energy consumers also need to make investment decisions and do so without guarantees of a certain return.

The purpose of the design is not to remove all risk or uncertainty

The efficient level of risk is very unlikely to be zero – just as the efficient level of reliability is not 0% USE. There are trade-offs and consumers have consistently indicated that they are not willing to pay the price for eliminating all supply interruptions. The NEM has already made the mistake of "gold-plating" in the distribution networks, at considerable additional costs to consumers for marginal benefits in supply reliability. It is critical that the same mistake is not made again in the area of wholesale supply reliability particularly noting that wholesale market USE has been "but a drop in all the oceans" of overall supply interruptions to consumers.

We see a liberalised rules-based market as an efficient way to manage the risk and uncertainty that consumers are prepared to bear.

The post 2025 market is being designed to meet the Reliability Panel's reliability standard

We have previously expressed our disappointment at the lack of consultation prior to the selection of the 0.0006% USE interim reliability standard[3]. This is meant to be a temporary standard that expires in 2025. The post 2025 market design should be designed to meet the reliability standard set by the Reliability Panel - currently 0.002%USE - which undertakes a robust stakeholder consultation process.

So we are pleased to see the comment (p.45):

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[2] See p.2 https://www.aemc.gov.au/sites/default/files/documents/rule_change_submissionerc0251_-_australian_energy_council_-_20200116.pdf

[3] See https://euaa.com.au/euaa-submission-energy-security-board-review/

"Reliability standard and settings – the ESB considers the current process whereby the Reliability Panel has responsibility to regularly review and (where relevant) recommend changes to the Reliability Standard and settings remains appropriate. The ESB notes that the Panel will start its next regular review in early 2021."

Notwithstanding this, the ESB design principles should still be stress tested against a higher reliability standard in the event of future intervention.

Be cautious about how to incorporate resilience

The concept of 'resilience' or what AEMO defines as[4]:

"…the ability of the system to limit the extent, severity, and duration of system degradation following an extreme event."

is having renewed focus. Resilience is separate from reliability. We are told that the current Electrical Sector Climate Information Project (ESCIP) being undertaken by AEMO/BOM/CSIRO will be a major focus of the 2022 ISP. The only mention of resilience in the Consultation Paper is in the context of ESS – frequency control and inertia to reduce the risk of system disturbances (pp 66-7).

The AEMO argument is that the electricity system resilience is in decline, particularly due to climate change. The ESCIP is looking at 'compound' events e.g. heat wave + bushfires both occurring simultaneously in multiple locations impacting supply, as another category on high impact/low probability (HILP) events. Our concern is that this may eventuate as a reason for additional expenditure of generation (e.g. RERT) and network augmentation without a thorough understanding of its nature, cost and consumers' willingness to pay.

For example:

- The system has traditionally not been designed to cope with major unexpected events e.g. earthquake or a Category 5 cyclone; the approach has been to mitigate the impact to some extent and then recover as quickly as possible
- the way the ESCIP study was presented to stakeholders in a recent AEMO Forecasting Working Group was in the context of increased tail risk which suggests increased centralised procurement of reserves may be an outcome.

In considering this issue, it should be noted that the probability of such an event is low, and the probability of an event that has been included for in any "resilience" planning arrangement, is even lower. Absent duplicating all the supply side, at considerable cost, the potential for some impact from such a "tail risk" HILP event remains.

We note the AER also recently decided not to pursue valuation of Widespread and Long Duration Outages given the problems with measurement of their dollar value.

[4] See Chapter 8 of the 2020 ISP https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--8.pdf?la=en

The market model needs to aware of significant stranded asset risk

It is very surprising that the Consultation Paper makes no mention of stranded asset risk along the supply chain. The only similar reference is where the risk lies for over (investors) or under (consumers through RRO/REET) procurement in the resource adequacy workstream (p.37). But this risk exists in many of the workstreams.
We would encourage the ESB to consider this matter more closely. The Paper's rejection of a centralised capacity market has much to do with over procurement/stranded asset risk on consumers. A decentralised capacity market does not remove these risks – it only reallocates who should bear the costs.

A major concern of consumers around the ISP is the potential stranded asset risk from building 60-70 year life regulated assets in what we all agree is a rapidly changing technology world. Consumers are being asked to support projects like Project Energy Connect, in part because of the purported benefits from connecting new renewable generation which has a 20-25 year asset life. Those supporting it are also claiming that rapid technology advances and significant cost reductions will also mean batteries will be much more efficient for firming than gas fired generation. Will distributed renewables in outback NSW be more competitive in 2050 (when the first round of renewable generation is being replaced) than batteries in South Australia?

Consumers cannot support a model that has them bearing an inefficient and inequitable share of that risk and we encourage the ESB to pursue new approaches to ensure consumers are not the risk backstop for the investments of others.

Implementation should seek to avoid sharp shocks to consumers

While the winners from change will want it to occur quickly, the losers are not so keen. There is always a balance to be struck as to how quickly reform should occur even when there is a clear overall forecast improvement in how the NEO is achieved. Change, particularly when based on a forecast of benefit, should minimise unintended consequences and collateral damage to particular consumer groups and be cognisant of contractual arrangements they have entered into.

Models for change should recognise what large consumers can and cannot do

Large loads have traditionally provided a range of system services and many stakeholders are recognising the important role they can play in the future market. Smelters are now seen as a giant battery. Large consumers are seen as an important cog in the system reliability and security equation.

The days of a 'set and forget' electricity contract are long past. Our members recognise they have to develop increased sophistication in their energy management activities. The increased focus on demand response as a major contributor to system stability and reliability in the future is well understood. However, these businesses are in business to make their products, not to 'play' the electricity market.

Those proposing market reforms need to be fully aware of what large customers can and cannot do, as well as what they may be willing to do, and what are the appropriate incentives to optimise their contribution for their business and the market.

Just as generators seek to earn a revenue stream from the services they provide, so do large consumers. But in designing this revenue stream it needs to be recognised that users are not the mirror image of the supply side.

Once a model is decided and implementation starts, then Governments have to be willing to step back and give it time to work

We have seen many examples of both Federal and State Governments directly intervening in the NEM for a variety of reasons. Some stakeholders have complained about a particular outcome that does not suit their commercial interests and Governments have to be 'seen to be doing something'. Unintended consequences, and costs to consumers, abound.

As we noted above, Government intervention is not going to stop. Not all of this intervention is against consumers interests. However, Governments need to be less willing to engage in short term reactions when it may appear one part of the new model is not working as intended.

The Paper notes (p.30) the risk that Governments may not be willing to tolerate periods of high pricing required to drive investment and talks about the risks around policy uncertainty and government intervention, commenting (p.36):

> *"The key question related to resource adequacy is whether the investment incentives in the NEM will maintain reliability at the lowest cost to consumers within an environment of continued government intervention."*

The measures proposed need to reduce the desire/need for Governments to intervene and any intervention should work to support the market rather than disrupt it. The Paper rightly promotes the benefits of trials using, for example, regulatory sandboxes.

Given the implementation of the agreed post 2025 model will be an evolution rather than a revolution, success will be measured over time not just in terms of a particular element but in terms of how the 'whole' works interdependently. This will take time and a degree of patience will be required. The advocates of a particular change should be cautious of their claims lest a short-term delay in benefits provides an excuse for inefficient Government intervention.

We think there is benefit in having a formal scheduled review date – say by 1 January 2028.

RESOURCE ADEQUACY MECHANISMS

In looking at what additional measures might be required, we note the range of current indicators available to the potential investor - the ESOO (where the 2020 edition sees no risk of breaching the 0.002% standard until 2029/30), the RRO, the ISP and its transmission investment plans and, until 2025, the IRM. We also note that the ESOO USE forecast does not include a significant volume of forecast new generation projects that are in AEMO's 'advanced' status rather than the 'committed' status. We note that if you include that generation the forecast of future USE disappears. Then of course there is the potential of Federal and State Government intervention either directly though building generation or investment support e.g. UNGI and CEFC.

The rate of development of distributed energy resources suggests the forward price curve and issues around minimum demand is not a disincentive to investment in that technology. Various State and Territory Government schemes are underwriting significant new capacity. Rather, the limiting factor seems to be more one of getting grid access.

While we understand the concerns outlined in the paper regarding potential barriers to increased investment in scheduled generation e.g. short forward curve, unpriced services, uncertainty on whether a large load might exit, we need to be careful not to impose too high costs on consumers for marginal benefit given the reliability outlook. Nevertheless, we recognise that forecast can change and the market design needs to be prepared.

We agree that scarcity pricing may not be sufficient in the future to stimulate enough investment to meet expectations on forecasts of reliability during the transition. This will particularly be the case when Government get nervous about high spot prices. But the current market is energy only in name only given the myriad of in-market and out-of-market instruments available to ensure resource adequacy. While the former put over-procurement risk on generators, the gradual expansion of the latter, especially backstop measures, have pushed this risk and its costs, on to consumers.

We support further consideration of an operating reserve. We look forward to seeing more detail on how it might work and the governance arrangements before we are able to express a view. For example, the Paper refers to procurement through a:

> *"Central body (ideally a body representing consumer interests and accountable for their outcomes) would determine the principles to be used by the System Operator (DO) to periodically determine the Operating Reserve Demand Curves (ORDCS)"*

It is important for the ESB to examine these mechanisms and to analyse their benefits in the face of Government intervention. We have real concerns around the risk of over procurement that consumers will bear. We are still paying off the gold-plated network from a decade ago.

We note that whatever form this operating reserve takes, it is still market intervention, albeit hopefully only a small one, and will result in a distortion of the normal market investment and dispatch signals. Our preference at this stage is for no change to the existing 'as required' RRO mechanism given it was built on the reasonable assumption that new physical capacity will follow to support contract arrangements entered into by liable parties. It was extensively debated very recently and has yet to be actually triggered. More evidence is required to justify an opinion that it would fail before it is even tried.

Given the 2020 ESOO forecast, we do not see the benefit of having the RRO 'always on' given its potential impact on market psychology. Will the market look to rely on it too much and not draw on the other market-based mechanisms when they could be lower cost?

We do not support moving from a 1 in 2 year peak to a 1 in 10 year peak which seems a back door method of tightening the reliability standard. We support it continuing to be based on financial, not physical, contracts to underpin market liquidity.

We agree with the concept of a 'backstop' as a last resort, not a regular part of the market. We prefer in-market rather than out of market measures and so see the RERT as a last resort. We wish to avoid a situation where RERT procurement ends up taking in-market resources out of market. This put unnecessary risk on to consumers who are not best placed to bear it.

We agree the ESB's proposal to not further explore:

- changes to the reliability standard and settings
- changes to RERT
- a scarcity price adder

AGEING THERMAL GENERATION STRATEGY

As we noted above there are many existing measures designed to incentivise building the required capacity to replace exiting coal stations. Given these measures plus the current policy requiring a public 42 months' notice of any closure, the materiality of any 'residual risk' depends on a number of factors highlighted in the Paper e.g.:

- exits are a normal part of an efficient market response
- exits can differ greatly in importance to the wider market e.g. an exit may be associated with the exit on a major load
- vertical integration provides a strong incentive for the gentailer to efficiently manage their generation book
- existing backstop measures
- sudden plant closure or exit that does not abide by the 42 months' notice

Yet, as recent events have shown, in the case of Liddell, even where:

- the Taskforce report saw no residual risk to prices, security or reliability,
- the market perceives there is no residual risk (NSW forward prices over the next few years are almost flat), and
- AEMO's 2020 ESOO says there is at worst a shortfall of ~150MW in 2023/24 (before the recent announcement on large scale batteries and renewables)

the Federal Government still found it necessary to promise it would provide 1,000 megawatts of new dispatchable energy in the Hunter Valley if the private sector does not commit to it by April 2021. This suggests the chances of any residual risk are extremely low as long as the threat of Government intervention is there. It may not be the most efficient response to a perceived market failure, but there is a strong willingness by the Government to use that lever.

We would be very cautious about supporting any payments being made to keep thermal stations around longer than the end of their notice period. Also there is perhaps a case for ensuring the announced closure date is in fact the closure date. New investors do not want to cover the risk that the plant will continue operating beyond its announced closure date.

At this stage it is very difficult to come to a view on whether additional measures are required simply because the design of all the other MDIs is yet to be finalised. We look forward to seeing other submissions on this Consultation Paper to assist in forming our view.

ESSENTIAL SYSTEM SERVICES

The exit of thermal generators which had provided the necessary non-market power system services for the secure operation of the NEM e.g. system strength, voltage control and inertia for free means that new providers of these services will be required. Our members have had to bear the high costs of these services being procured on a regular basis by AEMO, most recently with the islanding of South Australia earlier this year. The assumption is that consumers will continue to pay for these costs, when in fact a fair proportion of the on-going need for these services is caused by the shift to asynchronous inverter connected generation that does not bear the full costs they impose on the power system through their connection to the grid.

So, the first step is to support the AEMC 'do no harm' principle applying to generator connection standards with the costs and risks being borne directly by those market participants as opposed to the services being included in the RAB of the host network service provider. Once this principle is applied, then we agree with the general approach of a spot market-based solution for the remaining essential system services. These services are most efficiently provided by a rules framework providing for revenue streams to be earned by market participants as spot market-based procurement, not by AEMO intervention and procurement. Although we believe there is an argument for AEMO to retain some form of 'last resort' directions power as it does with the spot market.

The reforms should also recognise the benefits that large consumer loads provide to the market e.g. a stable and predictable load provided by smelters to help in a range of areas e.g. minimum load.

We agree with market-based provision of operating reserves, frequency control and a substantial part of inertia.

We support the ESB further exploring the ERM/CS Energy proposal to combine inertia and other services into a combined "synchronous services" product given our understanding of how it would operate:

- Any party would be able to provide ESS
- That provision could be either in a bundled form of an individual service
- In each case there would be only one revenue stream – for a bundled product or an individual product
- AEMO would have the choice of which is the lowest cost way of buying the bundle it needs

We agree there may be limits to the market provision of power system services and where this is the case, they may be best provided by TNSPs. This can bring economies of scale vs individual renewable generators providing their own in order to meet the required connection standards. Alternatively, a generator could also contract for the provision of the required services with other connecting generators to facilitate them meeting their connection agreement requirements.

Where the services are provided by TNSP's, there is an important distinction between provision and payment. Our view is the total cost of these services should be met by generators and then recovered through hedge/spot prices in a competitive market.

The recently released AEMC System Strength frameworks review only partially achieves this objective. While stronger technical standards for generator grid connection will reduce the overall system strength requirements, the remaining system strength requirements will be part of the TNSPs ‘prescribed system services’ i.e. part of the AER regulated revenue that are recovered from consumers through TUOS. AER regulation of the TNSP’s revenue will ensure the costs are ‘prudent and efficient’. Generators would pay the ‘marginal’ costs of provision with consumer left with the ‘residual’ costs. We look forward to undertaking a more detailed analysis of the proposed pricing approach with a view to ensuring the maximum amount of costs are recovered via wholesale markets.

We support the concept of some flexibility in the regulatory framework, recognising there are costs and benefits. Given the many moving parts in the chosen option, there is merit of undertaking trials as this will provide the opportunity to test concepts. Also, the fact that it is a trial will require patience from stakeholders and Governments to allow the trial to proceed. Our concern though is that there is an equitable sharing of risk associated with any trial – consumers should not be expected to always pick up the bill when it doesn’t work out as expected.

SCHEDULING AND AHEAD MARKETS

The EUAA supports further work on the Unit Commitment for Security mechanism plus system service ahead scheduling with participation in the ahead market voluntary. This is consistent with our principle of relying on market-based provision of services as much as possible.

We support the ESB decision to not proceed with a compulsory ahead market.

TWO-SIDED MARKETS

The EUAA has been a strong supporter of better integration of DER into the market and support the ESB’s effective combination of the two sided and DER workstreams. While it does provide our members with opportunity to limit their exposure to market prices, it importantly provides increased opportunity for the market to efficiently deliver an outcome that meets the NEO, minimising the reliance on inefficient out of market measures like RERT and strategic reserve.

All sorts of predictions have been made about the potential contribution of demand response. In considering this potential, it is important to consider the “energy only” market framework of the NEM and not compare the NEM to the level of demand response in other “capacity” markets where a large level of capacity payments are made for demand response that may be rarely, if ever, dispatched.

Some forecasts of the timing and potential contribution seem to be quite optimistic. Yes, some large users have been using it for some time as part of their PPAs T&Cs, other take a proportion of spot market exposure. Others are seeking to understand its potential role. Our members see it as a developing option to help them manage their market exposure but they are at different stages on their journey as they seek to better understand their business’s ability to provide demand response:

- how can they adjust their production processes to take advantage of it without sacrificing process efficiency and product output? after all their core business is making widgets, not playing in the demand response market, and
- what level of risk are they prepared to take on?

As large consumers get a better understanding of these issues, it is very important that they have choice – whether or not to engage and if yes, the method of that engagement (direct, aggregator or retailer), ensuring they are treated equitably with appropriate protections and complexity is minimised.

It is encouraging to see the range of measures that are currently underway to encourage greater demand side participation. We offer the following comments on one – the Wholesale Demand Response Mechanism currently being implemented by AEMO – based on our participation in the AEMO Working Group.

We are concerned that it seems that AEMO is seeking to make participating in WDR the mirror image of generators bidding into the market on 5 minute intervals. This imposes immense obligations on WDR providers that suggest the effort to participate is not worth the establishment and compliance costs and risks for those sites that require longer than 5 minutes to provide demand response.
WDR is likely to be suitable only for those sites that have technologies, such as on-site backup generation or batteries, that can respond quickly within the 5 minutes time requirement to meet their demand response scheduled target.

The scheduling and dispatch process needs to be flexible to recognise the different abilities of particular consumers to participate.

We support the staged approach set out in the Consultation Paper.

VALUING DEMAND FLEXIBILITY AND INTEGRATING DER

The Consultation Paper sets out the wide range of initiatives currently underway to facilitate DER integration. We agree with the six considerations described in the Paper and offer the following comments:

- It is important to follow the 'causer pays' principle e.g. the failure of inverter technology to keep pace with market developments has effectively meant that costs of DER that should have been borne by the DER providers have been placed on all consumers, many of whom do not have DER
- We support the move to cost reflective network tariffs as quickly as possible; we have supported the St Vincent de Paul (SVDP) and SA Power Networks (SAPN) proposal to delete NER clause 6.1.4 that prevents network charging for exports with DER generators having the choice of whether they wish to export more to the grid
- The AER's consideration of network capex and opex requirements for increased integration is making a good start with the recent Victorian DNSP draft decisions; the network response should not always be 'we need more money'
- As shown by the current work on implementing WDR discussed above, there needs to be balance in setting the rules for participation and compliance or take-up will be much less than expected
- As noted above in the two-sided markets discussion, choice is very important for consumers – to participate or not participate and, if the former, a range of options for that participation.

TRANSMISSION ACCESS REFORM (CoGaTI)

Like many stakeholders the EUAA have been involved in the extensive consultation undertaken by the AEMC over the last 18 months. The EUAA commend the AEMC on its efforts to explain this complex reform to energy users especially during a period of continuous volatility in the energy policy and regulatory landscape.

After consulting with a wide range of EUAA stakeholders including substantive discussion with a number of highly engaged energy users, we are of the view that the transmission access reform package as presented should not proceed.

We have made a submission to the AEMC (19 October 2020) where we explain our reasons for this position, provide specific feedback on elements of the reform and provide some views on how to develop a more equitable approach to funding Renewable Energy Zones in the first instance and potentially all new transmission, especially interconnectors, into the future.

For the purpose of this submission we provide the following extracts from our submission.

Transmission Access Reform and Competing Agendas

Transmission access reform has been a topic of debate for several years as market bodies, market participants and consumers grapple with a rapidly changing market environment. The focus of the debate, and therefore the desired outcome of any proposed reform, differs from stakeholder to stakeholder.

- <u>Consumers</u>; facing a significant increase in network costs due to the rapid transition of energy markets (and having already suffered from network "gold plating"), are looking for alternate models of cost recovery and risk allocation. We are seeking a more equitable approach where all market participants pay costs where they are beneficiaries (or where they have caused a problem) of new investment and carry risks where it is clear they are in the best position to manage them. Consumers also have growing concerns associated with stranded asset risk driven by a combination of fundamental changes in technology and consumer usage patterns and a mismatch of asset lifecycle where 50-year transmission assets are largely being built to connect generation assets with an operational life of 20 years. Under the existing method of cost recovery, consumers bear all of this stranded asset risk.
- <u>Transmission Network Services Providers</u>; facing a significant investment challenge driven by the rapid transition of energy markets and the emergence of the "actionable" Integrated System Plan (ISP) are looking to protect as much of their capital expenditure as possible by including all network augmentation as part of their Regulated Asset Base (RAB). As with consumers, networks to see emerging issues associated with stranded asset risk and the prospect they may be required to write off the residual value of underutilised or stranded assets (as per recent discussion about writing down asset values post so called network "gold plating").
- <u>New entrant generators</u> having soaked up all available network access while making minimal financial contribution beyond their own connection assets, are looking to continue to gain access to vastly expanded network capacity while avoiding deep augmentation costs that are, in many cases, being driven by the location of new generation in weak parts of the network or where there is no network at all. To be fair, a

growing number of new entrant generators are open to part or fulling funding of new transmission provided they are given appropriate, long-term access rights, which we think is a reasonable request.

- Existing generators, regardless of fuel source, are beginning to face significant constraint issues and adverse Marginal Loss Factors (MLF) associated with a transmission network straining to accept new generation in diverse locations. This situation is having a significant negative impact on the financial viability of these generators who, after careful due diligence, find their projects are now being materially impacted by poorly located new entrant generators. Arguments have been made that congestion should be a problem for equity to solve, not customers. However, experience to date points to customers continuing to pay for new transmission to relieve congestion, essentially paying to resolve problems created by others.
- AEMO, are keen to see the "actionable" ISP come to fruition. The 2020 ISP is a significant piece of work and has the support of governments who seem willing to assist actionable projects so they are built ASAP. From what we have observed, the main game of many market participants is to see congestion solved via the ISP and REZ, which means consumers will end up paying for a regulated transmission solution, which is no different to the current state.
- Governments, either through their concern regarding reliability, consumer prices or to help fulfil ambitious renewable energy targets, want to see the rapid roll-out of new transmission assets. The ISP provides a viable vehicle for this, hence their support. Beyond the ISP we see "independent" action being taken by state governments to relieve congestion where it has occurred, even going so far as to avoid the RIT-T framework and proper scrutiny by the AER.

Unfortunately for consumers (and the AEMC), many of these agendas compete directly with the proposed transmission access reform package. Consumers see the real danger that even if these reforms are implemented they become largely irrelevant and modelled benefits evaporate. Our reality is that we do not see the actions of other stakeholders subsiding, if anything we see these actions increasing over time.

We recognise that attempting to model long-term net benefits in this environment would be like trying to nail jelly to a wall whilst the wall is moving. It must be a near impossible task which also means the results of such modelling must be treated with caution.

In this environment, genuine sharing of risks and cost across a broad group of market participants is not only warranted but essential.

In earlier discussion papers we are heartened to see the AEMC recognise that the existing access and charging arrangements for transmission may no longer be fit for purpose.

> *"…the current access regime needs to evolve to allow the risk and cost of generation investment to compliment planning and investment in transmission. Building transmission to benefit generators means that generators should pay for this transmission investment."*[5]

> *"While generators are able to underwrite transmission investment on the shared network to reduce congestion, doing so would improve the access of all generators. Each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so while enjoying the benefits that the transmission infrastructure provides to all generators: a free-rider problem. As a*

[5] https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

consequence, a regulated, centralised approach to transmission investment has been adopted to date, which may be poorly coordinated with the market-based approach to generation investment. As generators only pay the direct costs associated with facilitating their connection, the price they face does not fully reflect locational signals, and generators do not receive any guaranteed level of access to the transmission network." [6]

The EUAA are of the view that the current arrangements do not fully serve the long-term interests of consumers, new entrant generators or networks. For consumers, we see two key issues that needed to be addressed by the AEMC as it considered transmission access reform that sadly, the current reform package does not resolve.

Equitable Risk Allocation

In our many submissions on the transmission access reforms and in our advocacy generally we have continually pointed to the risks associated with the rapidly changing energy market and the impacts on the feasibility of a number of proposed transmission assets such as the Energy Connect project, Project Marinus and the transmission upgrade to facilitate Snowy 2.0.

Project Energy Connect, an ISP priority project, is the most current example of the risk consumers are being asked to take. Over the last 12 months we have seen the capital cost of this project escalate from the original $1.53 billion to $2.4 billion and net benefits decrease from $924 million to as low as $150 million. Aside from the project now delivering significantly lower, some may say "skinny" benefits, especially given the cost, the gas market forecasts used to drive the fuel cost savings, and therefore the benefits to consumers, are highly contested.

We also see significant changes in at either end of the interconnector, that over time could seriously undermine the expected net benefits for consumers. New generation is being committed within regions to ensure supply as is technology to address system strength, while consumer usage is changing (and will continue to change). This is not meant to be a criticism of Project Energy Connect, it may over time deliver benefits to consumers, but there may also be periods of time where it does not.

Unfortunately, the current transmission access reform package does not address the issue of risk allocation in a volatile environment so consumers will be expected to absorb these risks via their monthly energy bill for decades to come.

Equitable Cost Allocation

The existing cost recovery model for regulated assets like transmission assumes that as society in general is the beneficiary of the investment that all costs should also be socialised. This is reasonable provided all benefits are socialised, which progressively they are not.

Once again, using Project Energy Connect as an example, it has been designed, in part, to facilitate significant new generation, specifically via a number of ISP identified Renewable Energy Zone. This new generation, being privately owned and operated, is set to gain significant financial benefit from this asset while consumers cover the cost associated with this access.

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[6] https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

This is a similar situation to a vast majority of ISP "actionable" projects and is certainly the case for the many REZ's identified in the ISP, which are being pursued for the sole purpose of connecting new entrant generators to the NEM.

It must be recognised that consumers have no control over where these assets are being located nor do they have any control over the financial viability or operation of these assets, but are currently expected to carry the cost, volume and technology risks associated with these decision. We are not arguing that consumers do not benefit from most of these investments but we do argue that they are not the sole beneficiaries. We do contest that all parties who benefit from investments in new transmission should pay their fair share.

We recognise that moving to generator co-contribution could result in slightly higher contract prices (i.e. PPA's) as project proponents seek to recover these additional costs. So yes, while the customer will always pay we should not continue to be asked to absorb aspects of project risks and costs that we have no control over or be faced with paying "full weight" for underutilised assets. Further, we contend that that exposing more network costs to open markets and competition will drive better outcomes for consumers compared to a regulated environment that, despite good intentions to deliver a result that replicates a competitive market outcome, has not always proven to be so.

Therefore, we firmly believe that commercial entities should make a reasonable co-contribution to the cost and maintenance of new transmission assets, and in the case of REZ, perhaps the entire cost. This being the case we believe it entirely reasonable that new entrant generators who make a significant financial contribution should be granted firm access rights or a form of financial transmission right. To achieve this outcome, we had hoped that a form of Optional Firm Access (OFR), working in concert with an enhanced Scale Efficient Network Extension (SENE) framework would be central to the transmission access reform agenda.

Unfortunately, we do not see how the current transmission access and reform package achieves any of this.

EVALUATION FRAMEWORK

We agree with the two stage evaluation framework set out in the Appendix.

Once again, thank you for the opportunity to make this formal submission and for the extensive engagement to date. We look forward to continuing our participation in the post 2025 market design process.

Andrew Richards
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Energy Users Association of Australia