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Dr Kerry Schott

Chair, Energy Security Board

Submitted by email: **info@esb.org.au**

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Dear Kerry,

Delivering Affordability and Managing Flexibility During Australia's Energy Transition

AGL Submission on the Energy Security Board's Post-2025 Market Design Consultation Paper

Introduction

AGL welcomes the opportunity to comment on the Energy Security Board's consultation paper. The Post 2025 Market Design project provides a critical opportunity to assess and update the design of the National Electricity Market, to ensure it is fit for purpose for the energy transition that is underway. This consultation paper is an important opportunity to take stock of the wide range of market design initiatives and consider them as a package.

We welcome the engagement to date and the willingness to take on board stakeholder input, which has been reflected in some of the provisional positions in the consultation paper. There has been an increasing focus on drawing interlinkages between the disparate and sometimes overlapping market design initiatives, and we welcome this aspect of the paper. This needs to be further refined in the next phase of the process, along with empirical modelling to clearly quantify the benefits, and the costs to the system and how they flow through to energy consumers. This will be critical to ensuring development of a coherent and achievable reform program that maintains affordable and reliable power during Australia's energy transition.

In short, AGL considers this can be achieved with a package centred around the following four priorities:

- **development of an operating reserve** to provide additional market-based incentives for dispatchable power;
- **development of new markets for essential security services** (along the lines suggested in the consultation paper);
- **efficient build and use of transmission infrastructure to minimise the cost to consumers**; and
- **new frameworks for demand response and distributed energy resources**, to flatten load profiles, increase competitive pressure on networks, and thereby contribute maximum value to owners and the broader consumers.

Each of theses four priorities are discussed in more detail below. In addition, we return at the end of this Submission to the issue of the coherence, focus and delivery of the overall reform package, and potential additional measures to underpin confidence in the transition to these reformed market arrangements.

Broad AGL approach

AGL believes the energy transition will be shaped by the forces of customer, community and technology. Customers are seeking affordable energy prices, but are increasingly interested in greater choice about their own energy production and consumption, and their carbon footprint. Community attitudes will continue to influence public policy choices around reliability standards and sustainability, and cost trade-offs associated with these. Technology is driving down costs of new forms of energy and storage, leading to a system characterised by greater distribution and flexibility. This provides enormous opportunities to benefit consumers and reduce emissions, but this changing energy mix requires complementary adjustments to maintain grid reliability and stability.

Delivering on consumer expectations regarding affordability, however, will be key to a sustainable market design, and Appendix 1 illustrates how market design could be driven by a consumer perspective.

AGL recognises the strengths of the current market design and that the NEM must continue to provide investment signals to support this energy transition. We have invested in new firm capacity in recent years including the first gas-fired peaking plant in the NEM in eight years at Barkers Inlet SA and an upgrade of 100MW of capacity under way at the Bayswater plant in NSW. We are progressing investments in a range of firming capacity options which complement growing renewable generation, fast-start gas-fired peaking plant at Newcastle, a commitment to install 850MW of batteries across the NEM by FY24 and, in partnership with our customers, intend to develop 350MW of 'virtual power plants' drawing on distributed energy and storage. This reflects our confidence in the signals the market is providing.

AGL therefore approaches the question of market reform with the following principles in mind:

- good customer outcomes – in terms of price, choice, reliability and perceptions of fairness – will be critically important for any market design to be sustained;
- any market design needs to be robust over time to a range of outcomes in the interplay of the three key forces of customer, community and technology, and needs to be able to maintain reliability and security at least cost under different technological mixes;
- changes in market design requires careful consideration of the costs and benefits, including the impacts on price and investment incentives, and assessment of transition costs to new market rules;
- Changes must deliver demonstrable improvement that provides confidence to communities and government that system goals will be achieved.

Market design initiatives therefore need to respond to clear evidence of missing markets which cause undersupply of critical services. Changes should carefully target those market gaps and be able to provide clear and demonstrable consumer and community outcomes. They should be phased and coordinated to avoid unintended consequences for supply or consumers.

AGL's detailed views on particular market design initiatives are outlined in Appendix 2, and below is an overview of our approach with a focus on the four priorities highlighted above, grouping related solutions according to the problem being addressed.

Development of an operating reserve to provide additional market-based incentives for dispatchable power *(Market Design Initiatives A & B)*

Debate over resource adequacy mechanisms (RAMs) is likely to be the most contested, and is in some ways the most fundamental market design question – should the NEM remain essentially built around an energy only market or does it need to adopt some form of capacity market arrangement? The ESB appropriately presents a range of views, with different stakeholder perceptions about the 'investability' of the current market, and the variety of international experience with different market designs.

In AGL's view there is not clear evidence of a generalised 'missing market' for resource adequacy into the future. As indicated, we are investing in new capacity, and can see technological developments that will contribute to reliability over time within the current framework (especially around the declining costs of batteries and distributed energy resources). Many of the reasons for current apparent gaps outlined in the ESB report – relating to policy uncertainty and out-of-market developments – may not be permanent features warranting re-design.

The clearest area we can see a current gap is the adequacy of *dispatchable reserves* for the system. While reliability standards have generally been met in recent years, there appear to be too many instances where the operational reserve margin has not been sufficient to cover risks of unexpected events. Governments have reacted by creating a range of measures aimed at developing more emergency reserves to provide greater comfort in managing contingency events. Federal and State governments have developed interim and alternative reliability targets reflecting their concerns, and have used these tighter standards as a basis for policy interventions outside of the market.

This suggests to us that stronger arguments exist for introduction of an operating reserve market within the current NEM structure, essentially adding a new market service. As indicated in the consultation paper this can provide real time signals for dispatchable power. If well designed and credible, like any other real time signal, expectations will provide longer term signals for investment in dispatchable power. In principle an operating reserve could be introduced at modest overall cost given it targets a more specific missing market, can be relatively easily integrated into current market design, and can substantially replace existing expensive methods of reserve procurement.

The ESB consultation paper and background analytic work presents equivocal evidence on the need for an additional 'longer term' investment signal. These mechanisms can involve new costs to consumers, and important changes to risk allocation. They bring greater transitional considerations and uncertainty as they involve substantial new market arrangements.

AGL is therefore sceptical about the need for a new long-term signal. We will return to consider this important issue in the context of the overall reform package later in this covering Submission. Other market design initiatives contribute to addressing some of the underlying issues motivating consideration of such mechanisms. We see the market design initiatives around thermal closures as closely related to this question and will also address this at the end of this covering submission.

Development of new markets for essential security services *(Market Design Initiatives C & D)*

Essential System Services reform directions are relatively clear – and critically important. In line with the framework outlined above, AGL supports the directions outlined in the ESB consultation paper to underpin provision of essential system services through the transition.

The consultation paper clearly makes the case that there are missing markets for essential services like frequency control, inertia and system strength. Failure to properly incentivise these services will likely lead to increasingly costly directions and interventions to achieve system security, which will ultimately be borne by customers.

We broadly agree with the framework for gradually introducing market signals and ensuring these signals are appropriate. This will allow the markets for each service to be developed in a way that is least cost to energy consumers. Such signals will introduce more transparent competition for the provision of these services to the benefit of consumers – for example, a price signal for inertia could be met by existing power stations or new purpose built technologies, while frequency services can be provided by a range of assets. In some cases, legacy assets will be well placed to provide services. In other cases, new assets such as batteries, VPPs and new technologies will be well placed to provide services, facilitating the transition over time.

AGL supports the direction of the market design initiative on Ahead Markets. We agree that mandatory ahead markets are not warranted, and would impose significant transition costs for little benefit in terms of system security. On the other hand a good case has been made for the provision of improved information about unit commitment to the market operator. Together with creation of new markets for services, some of which will themselves involve elements of forward commitment, this will assist maintaining system security during the transition.

Efficient build and use of transmission infrastructure to minimise the cost to consumers *(Market Design Initiative G)*

The energy transition will involve, under all scenarios, a significant growth in renewable generation that has a very different geographic distribution than today's assets. This will necessarily require a significant build in transmission infrastructure to bring this generation to market and to improve system resilience and reliability.

It is therefore critical that this infrastructure is both built in an efficient manner – close to the best resources and in a planned manner – and used in the most efficient way to ensure consumer costs are minimised. Some new elements are now in place or proposed to achieve these outcomes, with the development of the Integrated System Plan (ISP) and a proposal for locational price signals for efficient transmission under the Coordination of Generation and Transmission Infrastructure (CoGATI).

Cost effective implementation of the ISP network projects will be the most critical. Existing market design elements, involving rigorous regulatory testing of network build, will need to retain a decisive role to avoid excessive costs being passed to consumers.

With respect to CoGATI, these reforms should be integrated with other market design elements, and carefully sequenced to minimise the costs of the considerable system development required. Locational network pricing and financial transmission rights will need to integrate and follow other new price signals involving resource adequacy or system services. This would require slowing the AEMC's review process so it can be considered with the full package in mid-2021.

New frameworks for demand response and distributed energy resources *(Market Design Initiatives E & F)*

Demand Response (DR) and Distributed Energy Resources (DER) have a key role in maintaining reliability and minimising cost by flattening load profiles, increasing competitive pressure on networks, and thereby contributing maximum value to owners and the broader consumers.

Distributed Energy and demand response are a critical part of the overall package, as they provide the clearest pathway to reducing system and consumer costs. Both can act to shift and flatten load and provide alternative ways of meeting peak demand. They can contribute to reducing network costs through introducing competition and providing alternatives to network solutions. Given the importance of network costs (see Appendix 1), putting in place the right market arrangements will facilitate the transition while maintaining affordability for customers.

DER and DR will contribute over time to addressing some of the problems identified under other market design initiatives, particularly resource adequacy and ESS. Increasingly integrated systems of renewable energy, storage, and electric vehicles and other flexible load will play a growing role, initially in distribution systems but ultimately in the overall grid. These technologies can provide value to both users in terms of energy services and autonomy, and to the grid through having multiple assets orchestrated to provide network and security services.

We support the ESB's staged approach to the introduction of two-sided markets. This will over time bring greater volumes of demand response into the system, reducing the need for expensive capacity and in keeping with market and technological developments.

DER is perhaps the area that requires most significant innovation in market design. This has been the most rapidly growing source of generation, and market arrangements and technical standards have fallen behind. DER resources risk being inefficiently curtailed to meet shorter term network constraints. Current arrangements inhibit the ability of participants and aggregators to extract full value for the system. Under most scenarios this growth will continue, so these barriers must be addressed.

AGL sees strong potential for value streams to be created by the orchestration of DER assets, and good market arrangements can introduce competitive pressures for networks, and share this value between owners and broader consumers. DER has potential to substitute for expensive network build, deliver value to owners and broader consumers, and provide alternatives ways of meeting system security requirements. Over time, electric vehicles will play an increasingly important role in this energy system, so market reform here has significance for the transport sector and its own energy transition.

Reform in the DER market requires action across a range of domains. It needs the development of technical standards to allow reliable integration of technologies, network regulation, consistent consumer protections, and new market institutions and frameworks to ensure competitively neutral arrangements.

Over the longer term, the trend will be towards increasingly autonomous consumers and communities, with different options for participation and aggregation in the market, and network connection. Putting in place the right market arrangements and institutions now will open the way for innovation while maintaining system reliability and security.

An overall market reform package needs to be carefully prioritised and sequenced, and take account of the interaction between design initiatives

The above suggests a significant reform agenda is needed to address emerging gaps in the existing market design, to ensure reliable and affordable power for consumers. This is illustrated by the substantial reform program outlined in figure 36 in the consultation paper, spanning the best part of a decade. Just taking the elements that are well established by the analysis in the consultation paper, this would involve:

- significant technical development to introduce a range of new Essential System Services markets, possibly including a Dynamic Operating Reserve;
- finalising new rules to implement locational pricing for transmission and enabling greater participation of demand side;
- determining a reform pathway to set up Distribution Market arrangements to ensure DER is well integrated with the grid and adding maximum value, possibly involving new institutions.

The development of this agenda will involve significant and sustained leadership and focus by market bodies and policy makers, and high levels of engagement with industry, consumer and other stakeholders. Implementation of this agenda will involve significant system development within the energy industry.

With this in mind we return to the threshold market design raised in this submission – the need for a long-term investment signal, and the related issue of an ageing thermal generation strategy. In determining any investment signal system reliability, price and risk allocation, and particularly the implications for consumers must be assessed and prioritised.

In addition to a conventional policy evaluation, any additional resource adequacy measure needs to be assessed in light of its incremental contribution to the overall reform objectives of delivering reliable and affordable power in an increasingly flexible system. As we have noted, several of the market design initiatives outlined above contribute to addressing identified market gaps. In particular, the operating reserve will increase incentives for dispatchable generation, essential system service markets will value the services provided by existing generation capacity, and demand response and DER reform will over time contribute flexible capacity to meeting tight market supply.

For all these reasons, AGL is sceptical about the need for an additional longer-term capacity price signal. We are not convinced it can assure reliability and supply at reasonable cost and risk. And we consider other design initiatives, combined with technological and other market developments, will address many of the mooted market gaps. There is a good prospect for a more focussed reform package to achieve the overall outcomes being sought.

If the ESB decides to proceed down the route of an additional long-term price signal, AGL will engage closely in further consideration of market design and impact modelling in the next phase of the post-2025 market design project. Of the capacity options, we would prefer a purpose-built decentralised mechanism where resource adequacy needs could be directly identified, and cost and risk trade-offs transparently assessed. We do not favour an option that builds on the Retailer Reliability Obligation (RRO) as this is unlikely to be fit for purpose. We note this measure has not yet been triggered or tested under current market conditions and settings. In our view, building on such a measure risks producing uncertain reliability impacts at relatively high consumer and compliance cost. Similarly, any capacity market mechanisms should be as neutral as possible between technologies, for example incentivising only new capacity could exacerbate disorderly exit issues.

Overall, though, AGL considers that compelling evidence of clear net benefits would be required to support progressing design of longer-term resource adequacy measures into 2021.

Customer and Community Confidence will be a key to sustainable change

On the related issue of the ageing thermal generator strategy, the preferred reform package outlined above will, with existing measures such as notice for closure, assist in orderly closure. For example, these assets, or alternatives, could receive incentives to provide security services. A well-designed operating reserve would bring additional dispatchable grid and distributed energy resources into the market. Improved unit commitment processes will give the operator more visibility of assets available for dispatch. This will be an important difference between future closures and those experienced in the recent past.

However, we recognise that this approach will take some time to settle, and for governments, communities and the market to be confident of this.

We therefore propose that the ESB give thought to the design of information-sharing structures to assist in orderly exit. These could involve developing protocols, governance and reporting around scenario planning and other ways to improve market understanding in the lead up to major thermal exits, with the aim of reinforcing market responses. Such an approach could involve input from energy market bodies, relevant authorities, customers, community stakeholders, and market participants (consistent with their disclosure and competition obligations). These processes would provide authoritative information to the public and decision makers about market prospects and scenarios, including the operation of any new price signals from the post-2025 market design process. Such processes may from time to time find additional closure policies, including contracting approaches, may need to be contemplated, but these should be well-flagged in advance and designed to reinforce market signals.

Conclusion

AGL looks forward to being involved in ongoing development of potential reform packages. The next phase must focus on empirical evidence of net benefits and costs of reform direction and particularly the interactions between the various initiatives under different scenarios. This should also take into account assessment of the capacity of the system to manage multiple transitions – which would also suggest a strong focus on prioritisation of reform.

If you have any queries about this submission, please contact Aleks Smits at ASmits@agl.com.au or Jenessa Rabone at JRabone@agl.com.au.

Yours sincerely,

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APPENDIX 1: A CONSUMER PERSPECTIVE ON MARKET DESIGN

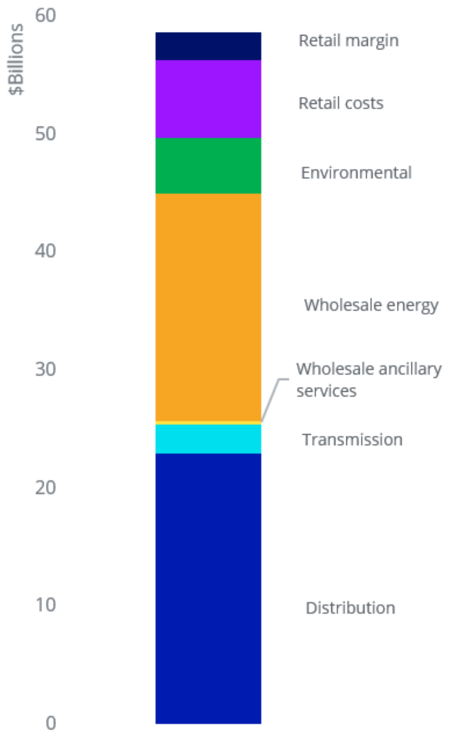
It is helpful to think about the forces impacting on the energy costs facing consumers (see Figure 1 below). This suggests a question to ask about market design – how will it impact on the future costs facing consumers?

Some key messages from this are:

- Wholesale electricity costs will move towards the cost of replacement capacity, involving combinations of firmed renewable generation. Costs will be determined by choices over reliability standards and resource adequacy, and can be minimised by efficient ways of bringing dispatchable grid assets, distributed energy, and demand response into the market.
- Ancillary services are likely to be a more important (explicit) cost in the system and it will be critical they face competitive pressures to force cost effective solutions.
- Turning to network costs, which make up 40 per cent of the costs facing consumers, market reform has a key role in restraining these and even finding opportunities to reduce network build costs.
- Transmission costs are likely to face upward pressure under most scenarios as the grid becomes more dispersed, highlighting the need for cost discipline on the build and price signals within the network to maximise efficiency.
- Distributed energy resources can play a key role in reducing distribution network and therefore consumer costs, highlighting the critical importance of market arrangements that can maximise its value for owners and the network.

Figure 1

Annual NEM costs



2018 NEM Costs: (Sources: ACCC, AEMO, AGL Analysis)

Existing trends

Retail costs and margin relatively stable

Environmental costs and their allocation affected by climate scenarios and mechanism

Wholesale costs likely to reflect cost of firmed renewable capacity over long term

Ancillary services will increase as previously co-produced wholesale services costed out but remain small part overall

Transmission likely rise as networks adjust for more VRE.

Distribution needs to undergo significant changes for the energy transition, smart use of DER key to minimising costs and avoiding overinvestment

Implication for Post 2025 market design reform program

- **Retail and Environmental** – not within scope in post-2025 exercise
- **Wholesale Energy:**
  - **Resource adequacy**: Dynamic operating reserve to secure extra insurance at modest cost, and improve incentives for dispatchable power. Capacity markets likely more upward pressure on costs, especially RRO option.
  - **Two-sided markets and DER**: Incremental steps to unlock demand response and DER value through orchestration can reduce need for capacity over longer term, and lower consumer cost.
- **Essential System Services**: Competitive procurement and valuation of system security services, including markets for inertia and reserves. Ahead 'unit commitment' will assist. Both avoid more expensive and frequent market directions to benefit of consumers.
- **Transmission**: Ongoing scrutiny of transmission network build to ensure least cost, gradual introduction of locational pricing and financial transmission rights (CoGATI) to ensure efficient use of infrastructure.
- **Distribution**: Network costs can be minimised and reduced through better use of DER, developing distribution market operator and competitive procurement of network services.

APPENDIX 2 – RESPONSES TO CONSULTATION QUESTIONS

<u>Section 4: Resource Adequacy Mechanisms – Market Design Initiative A</u>

> Are the current resource adequacy mechanisms within the NEM sufficient to drive investment in the quantity and mix of resources required through the transition?

The existing market arrangements provide strong mechanisms for signalling for the volume and timing of investment. The financial contracting market provides forward prices to signal for medium term investment needs, while the credibility and transparency of market signals and rules provides the basis for market participants to assess longer term investment signals. Real time pricing in the spot market signals for capacity to be available. AGL has progressed, and will continue to progress, investments in a mix of generating and storage technologies on the basis of these signals. Declining costs for storage and DER, and in the longer run new technologies, will mean that over time different mixes of resources will be brought into the NEM via these price signals to facilitate the energy transition.

We consider the ESB reforms under other MDIs will reinforce existing market signals on resource adequacy during the transition. Establishing security services, increasing DER and demand response participation, and efficient network investment will help to maintain system security and reliability at efficient costs for customers.

Nevertheless, there may be a need to further supplement this market design to ensure the quantity and mix of resources meets community expectations during this transition. For example, the combination of an increasing proportion of variable renewable energy (VRE) and ageing of thermal generators may increase the possibility of high impact events, even if overall market reliability settings are met on average. In these circumstances there may be market gap in the provision of reserves of dispatchable generation, and specifically to provide sufficient assurance that periodic events of market tightness do not progress to unserved energy. This may require additional dispatchable capacity to that which would be signaled by current market settings. As discussed below, an operating reserve may be a suitable way to address this issue within the market, in a way that evolves existing market design and that is consistent with affordable energy prices.

Resource adequacy within the NEM will also be impacted by settings outside of that market, for example notice of closure regulations and other government support for generation and storage capacity. Overall outcomes will be best if these outside settings are designed in a way that is consistent with, or reinforce, market settings.

> 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?

An operating reserve is a targeted market mechanism that would directly incentivise additional dispatchable capacity to be available as backup in times of market tightness. It also enables procurement of volumes that directly relate to insuring against contingencies in the system – the high impact low probability events, largest credible risks, or the forecast uncertainty measure. An operating reserve is aligned with AEMO's real time management of the system and Lack of Reserve calculations. This would complement the other market settings that are based on a Reliability Standard, which is probabilistic and less suited to real time system management. If well designed and credible, an operating reserve provides a signal regarding the total capacity and investment required in that region.

An operating reserve would provide an additional source of revenue for dispatchable generation. We expect this price signal would result in a greater proportion of dispatchable capacity entering the market over time compared with a base case. The costs of the operating reserve and participation by specific types of technologies would depend on the objectives and design of the scheme, which should be considered as the next steps for this workstream. For example, early design questions will include the types of services to be incentivised (short duration flexibility, longer duration dispatchability, or both) and how the operating reserve objectives are set and delivered.

The interactions between the operating reserve and the energy market (and other markets for security services) should be carefully considered to avoid unintended consequences. It will be important to design the operating reserve to maintain the incentives to participate in the energy market. Setting the operating reserve price cap at a proportion of the energy market price cap would skew participant bids towards energy markets first. It will also be important to establish markets for the "missing" security services to ensure the right resources are dispatched for that purpose.

An operating reserve is unlikely to have substantial impacts on energy financial contracting markets. As mentioned above, the operating reserve could be designed to maintain incentives to bid capacity into the energy market first and therefore would not negatively impact contracting activity. Depending on the design of the operating reserve and cost recovery, a separate derivative market for the operating reserve could develop.

Given the impacts of an operating reserve will depend on the specific design, we suggest the ESB develop a proposal for further assessment and comment by industry. We look forward to further engagement.

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?

The RRO was originally designed to ensure retailers and other market customers were appropriately hedging to support the market during periods of shortfall. While it is possible to adjust the RRO to provide longer term signals for capacity, we have concerns that adjusting the RRO to achieve a different policy objective and ambition will produce unanticipated costs and risks.

Removing the RRO trigger or introducing more stringent obligations regarding the amount and type of qualifying contracts may incentivise greater levels of contracting. However, the complexities involved in retailer hedging means it would be difficult to anticipate cost, impact on investment incentives, and the amount of resource capacity and reliability standard that is being delivered.

Some of the other design changes flagged in the ESB paper could involve substantial costs to consumers that need to be fully examined. The suggestion that retailers should hold contracts to cover 1 in 10 year peak demand would be at extremely high cost for the market. Individual retailer peak demands may occur at different times, so placing this obligation on individual retailers would lead to over-procurement. This would also exacerbate compliance issues and costs related to the uncertainty of large C&I loads. Similarly, requirements that the RRO be met by physically backed contracts reduces opportunities for risks to be managed at lower cost in the market, again potentially adding to costs.

If ESB considers that a capacity mechanism is part of the solution – and we are not convinced this is needed given technology developments and the range of complementary market design initiatives – we would suggest purpose-built decentralised mechanisms be considered to directly address resource adequacy objectives at least cost. Any mechanism to be contemplated should be as neutral as possible between different sources of capacity – for example, a mechanism focused solely on new capacity would distort the market and potentially increase risks of disorderly exit. We also reiterate that the ESB should consider the need for additional resource adequacy mechanisms in the context of the other workstreams, which will also assist with resource adequacy.

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?

We anticipate that an operating reserve, once fully operational, would significantly reduce the need for the RERT. Any retained RERT mechanism would return to being a true backstop that enables AEMO to procure out-of-market reserves to meet forecast shortfalls, instead of being regularly and systematically used as it has been these last few years.

Due to uncertainties around the operation of an RRO based mechanism (the RRO is yet to be tested), it would be difficult to anticipate the impact of an ‘enhanced RRO’ on AEMO’s incentives to procure RERT. The interaction between AEMO and retailer demand for contracts would be one of the complexities to be worked through should the ESB consider an enhanced RRO.

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?

In principle, energy policies should be streamlined and integrated to minimise any inconsistencies between jurisdictions, or duplications within jurisdictions.

Should a jurisdiction wish to alter the specifics of an energy policy, the costs and other impacts of the proposed changes should be thoroughly analysed to fully appreciate the additional costs to consumers in that state.

Should a jurisdiction set different requirements for in-state reserves as part of an operating reserve, this would increase the complexity of the measure. Constant adjustments could reduce its reliability as an investment signal. Similar considerations would apply to other capacity mechanisms.

If this approach is assumed, this could support the case for mechanisms that explicitly target capacity as this would provide clarity to investment signals with transparent costs for consumers in that jurisdiction. The enhanced RRO does not include explicit targets or easily determined costs.

Section 5: Aging Thermal Generation Strategy – Market Design Initiative B

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

AGL agrees that there are some risks with the market transition, as large thermal generators may have unexpected outages or face technical or economic issues that result in closure. A disorderly exit is more likely to create these types of risks, however we note that recent measures, such as closure notification obligations, and the other ESB workstreams will help to mitigate these risks. Energy market bodies should give ongoing attention to ensuring interventions in the market are fit for purpose, and that pricing for services procured supports the goals of orderly transition.

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

The new notice of closure rule and improvements to system planning are contributing to orderly management of the transition. We consider these recent reforms are improving the signals for investment and addressing the risks at least in part. Addressing the ESB's other workstreams will also contribute to ensuring the right mix of investment.

It is important that when a large generator exits the market, other generators are incentivised to remain and be available during a period where supply and demand may be tighter. This supports an orderly transition and is vital for system security and reliability. Clear market signals can indeed reduce these risks by allowing for orderly and sequential exit. We welcome recent efforts by AEMO to model contingencies, this will allow the market and policy makers to be better informed. If interventions are considered warranted in a particular circumstance, these should draw on and reinforce market signals to the extent possible, including via associated price signals.

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

AGL considers that addressing arrangements for security services and integrating DER and demand response will materially assist with the orderly closure of aging thermal generators during the market transition. However, we recognise that this approach may take some time to be implemented and gain full confidence.

AGL suggests that the ESB consider whether a structured information sharing process could assist ahead of the next large thermal closure. This could involve sharing information and scenario planning to improve the understanding of the closure and potential investments for both AEMO and industry, with the goal to facilitate an orderly transition (consistent with competition and disclosure obligations). If it becomes apparent that a shortfall will persist, ESB could investigate the possibility of temporary contracting options (discussed below).

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

There may be circumstances in which the economic conditions do not support the thermal generator remaining open, but the security services provided by the generator have not yet been replaced and are vital for the safe operation of the system. In these circumstances it may be cost effective and appropriate to contract with that generator to provide the required security services until replaced by the market.

Given the distortive market effects this may have, it should only be considered in emergency situations and to aid an orderly transition (ie only as a temporary measure while the services are replaced). It should be designed to have minimal impacts on the price signals in the spot market, and with clear and predictable operation.

There are risks to this approach that would need to be managed. In general, contracting with closing thermal generation to remain in the market has the potential to affect investment decisions for new assets. This may have the unintended consequence of stalling new investment decisions until there is certainty around the timing of the generator exiting the market. This underlines the importance of having transparent and timely processes for considering such actions.

Section 6: Essential System Services – Market Design Initiative C

What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? 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?

We are supportive of a dynamic operating reserve where reserve is procured and priced through a demand curve spot market. An operating reserve could support both resource adequacy (i.e. sufficient capacity to meet peak demand), and also provide valuable reserves to respond to contingency events. In our view the mechanism could be structured in a way to achieve both objectives.

The way in which operating reserves can act as a useful system service was broadly stated within Infigen Energy's rule change proposal that is currently being considered by the AEMC.

In our view, a dynamic operating reserve would not only provide an investment signal for resource adequacy, but would ensure that a quantity of reserves is available in the market at all times to respond to contingency events. The level of this reserve (i.e. the 'reserve margin') could be set at an economically efficient level to drive levels of security and reliability that meet the objectives of policy makers, while balancing the cost on consumers of ensuring sufficient reserves are in the market. As a starting point, the quantity of reserves to be procured might be set at the level of largest credible risk in the region. As described above, we consider there may be merit to capping the price of operating reserve at a lower limit to the energy market price cap to encourage participation in the energy market during periods of low available supply.

An operating reserve should be dynamically priced and optimised with the energy spot market to take account of available capacity in the system. We expect that an operating reserve would be structured so that a secondary market for a hedgeable product would also emerge. An operating reserve would provide an additional source of revenue for dispatchable generation, which would compete to provide that service (co-optimised with energy and FCAS bids). We would expect the price of an operating reserve to be very low most of the time, but providing a price signal for dispatchable capacity to be available during scarcity periods. It would also ensure that at periods of moderate and low operational demand there was sufficient generation available to meet contingency events.

We support further investigation into timescales of provision, regional characteristics, and call times of operating reserve.

What are your views about developing Fast Frequency Response with FCAS and developing a demand curve for Frequency Response? Will such a mechanism assist 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?

We support the introduction of new raise and lower fast frequency response (FFR) markets with a faster response time than the existing 6 second, 60 second, and 5 minute FCAS markets. We note that the development of FFR markets is also the subject of a current Rule Change with the AEMC, to which AGL has provided a submission in support[1].

The proposed rule is designed to facilitate quicker responses to frequency changes, since the rate of change of frequency following contingency events in the NEM has increased due to decreased inertia in

[1] See: https://thehub.agl.com.au/articles/2020/08/submission-to-the-aemc-system-services-rule-change-consultation

the power system, the increased frequency of extreme weather events, and the growth of VRE which has increased the variability of demand and supply and therefore the likelihood of contingency events.

New FFR markets are likely to be an effective mechanism to respond to these challenges. The proposal would increase investment incentives for providers of fast frequency response, which are currently not appropriately compensated for their unique fast-response capabilities. While new FFR markets may introduce new costs into the NEM, they should improve system resilience and the efficiency of dispatch for frequency response services, which should lead to savings in reduced demand for other FCAS categories and potential savings in inertia remediation.

The development of FFR markets should also consider recent consultation regarding the provision of mandatory primary frequency response (PFR). In our view, mandatory PFR and FFR should be considered jointly in the development of further mechanisms for frequency response.

Depending on how they are designed, both PFR and FFR markets could have implications for the quantity of inertia that is required to be otherwise procured, as frequency response can assist with arresting the rate of change of frequency in the same way as mechanical inertia.

We therefore consider that it is important to finalise PFR arrangements and establish FFR markets on a timeframe prior to 2025, utilising the established structure of FCAS markets, prior to making further decisions on mechanisms to address inertia shortfalls. In our view, there is no reason why FFR could not be progressed as a standalone rule change outside of the 2025 program of work.

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, 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?

We broadly support the characterisation of services put forward in the ESB's paper, as well as the possible roadmap of procurement and scheduling options for essential service (i.e. Figure 23). While in principle we support the dynamic efficiency of spot markets in pricing and procuring services, we consider there to be significant challenges in developing a spot market for inertia and system strength services.

Typically, there is ample supply of system strength and inertia in the NEM and the need for these services does not affect dispatch. However, when an undersupply of these services is forecast, synchronous generators which supply these services are dispatched in priority to non-synchronous generators, either through the curtailment of wind or system strength directions.

System strength directions were designed as a last resort mechanism to ensure the necessary units for system security were available at dispatch. As a last resort mechanism, they were designed to be used infrequently and they therefore provide compensation based on a simple formula, which does not provide an effective market signal for investment in these services since it does not account for scarcity and therefore does not reflect the long run cost of supply. .

Efficient price discovery is also likely to be difficult in a spot market for system strength since system strength is a local requirement and therefore multiple separate markets would be required for each region and each market may only have a few participants. This factor would also undermine the effectiveness of an inertia market, since the commitment of synchronous units for the provision of system strength and inertia cannot be separated.

We note that system strength and inertia can also be provided by non-generating infrastructure, such as synchronous condensers or spinning turbines. An optimal market design should therefore draw from services able to be provided by both generating and non-generating infrastructure, which may present challenges for a spot market model that is co-optimised with energy. However, it is worth noting that better utilisation of in-market resources for system services, especially compared to network solutions for system services, may also assist with providing additional revenue streams generation, which could have therefore improve resource adequacy objectives.

In energy and frequency markets, quantities are determined on the basis of forecasts, but the combination of generation units which can meet those is needs is determined by a central dispatch engine. This contrasts with system strength and inertia standards, where AEMO determines both the quantity to be procured and the minimum acceptable unit commitment combinations, based on their own modelling of the power system.

System strength and inertia requirements must be determined down to the unit combination level given the local nature of system strength markets, and the blocky nature of system strength and inertia requirements. As a result, the forces of demand and supply in a decentralised system strength or inertia market may not function as they would in most markets.

On the basis of these reasons, AGL considers the nature of system strength and inertia may make them more suitable to pricing through longer-term contracting, with a new mechanism for scheduling and dispatch of services. A centrally coordinated model for the provision of system strength and inertia services in the NEM with a competitive tender process for remediation (when a shortfall is identified) may therefore be worthy of further consideration.

Further consideration of the proposed UCS mechanism, discussed in more detail below, may provide an option for scheduling and dispatching these contracted services. However, we consider there is also merit to considering whether the existing predispatch process could evolve to provide similar results.

AGL proposed a similar approach (for inertia) in our 2016 AGL Inertia ancillary service market rule change request[2], which suggested that inertia services could be procured on a competitive basis by AEMO, similar to the provision of SRAS. Taking a forward-looking approach to future market reform, we consider that this model is again worthy of further consideration.

For example, we suggest that AEMO could assess system strength and inertia levels in the NEM through an ongoing transparent process which includes timely notification of forecast shortfalls. Following the assessment, AEMO could conduct a competitive procurement process to obtain tenders from market participants with proposed remediation solutions to address the identified system strength or inertia shortfall. Ideally, the procurement process would be technologically neutral, and therefore it would define the system strength shortfall without mandating the technology required to remedy it.

We note that where signalled plant exit or extended closure leads to a critical shortage of essential services, this procurement method could be expanded to provide for the contracting of necessary services with existing plant on an efficient basis, to ensure that the system remains secure following the anticipated closure of large thermal plant.

[2] See: https://www.aemc.gov.au/rule-changes/inertia-ancillary-service-market

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?

Appropriate regulatory frameworks are critical to manage the energy transition. This requires a balance between providing investment certainty for large-scale investment, while allowing a degree of flexibility to account for emerging technologies and short-term operational concerns.

With regard to services provided by network service providers, we consider the principles outlined by the AEMC in its determination regarding the contestability of energy services remain relevant.[3] Networks should not use regulated funding to compete with competitive business for the provision of services; this may stifle innovation from competitive businesses and may impact on the long-term delivery of services for the benefit of customers. Existing regulatory frameworks for network innovation (such as the demand management incentive scheme and innovation allowance) represent appropriate allowances for networks to undertake innovative activities. In our view, where the existing frameworks are not operating effectively, reforms should be considered through broader changes to network regulation, to ensure networks have the appropriate incentives in place to maximise the productivity of regulated funding and long-term benefits for customers.

More generally, market participants are subject to market settings that are specifically set as constraints to drive participant behaviour and provide long-term investment signals. The most obvious of these with reference to the NEM is the reliability standard, from which other critical market settings are set, such as the market price cap for generators, and the value of investment in additional network infrastructure to maintain system reliability.

To facilitate long-term investment, it is important that these underlying market settings remain steady over time.

Nevertheless, some degree of regulatory flexibility is likely to be beneficial in some cases, on matters which can be carefully controlled. This idea has been recently explored in some detail by the AEMC in their consideration of regulatory sandbox trials; that is, frameworks within which participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.

As AGL highlighted in its feedback to this consultation[4], we believe the regulatory sandbox package of reforms will provide an important opportunity to accelerate the development of innovative technologies and business models in the national energy markets to deliver greater benefits to customers.

In order to best facilitate these opportunities, we recommend that the eligibility requirements for regulatory waivers be extended to circumstances where there is evidence that the application of a rule is not fit-for-purpose in serving the long-term interests of consumers. In our view, this general principle should apply to all participants subject to the NER and NGR, including AEMO and network service providers.

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[3] See: https://www.aemc.gov.au/rule-changes/contestability-of-energy-services
[4] See: https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_epr0079_-_agl_energy_-_20220219.pdf

Section 7: Scheduling and Ahead Mechanisms – Market Design Initiative D

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 strongly support the ongoing utilisation of the NEM spot market to procure and price certain services, in particularly energy, frequency, and reserves. We do not consider there is a need to centrally price energy ahead of dispatch and see no strong basis for a focus on the development of a structured ahead market for energy or services. We do not support any steps to move away from the mandatory gross pool design of the NEM.

Where there is a demand for physical contracts for electricity or system service delivery at an ahead price, we consider these can be determined on a bilateral basis (i.e. not centrally cleared through a market).

Issues relating to the proposed development of ahead markets are similar to those discussed in recent consultations regarding the development of a voluntary short-term forward market (STFM),[5] where the AEMC found that the development of short-term ahead markets were unlikely to advance the National Electricity Objective.

To understand the way that participants currently manage their risk and determine the underlying level of demand for short term hedge contracts, the AEMC consulted widely and found that there is currently limited demand for short term hedge products in the market and that demand is sporadic and bespoke. Therefore, if introduced, the Commission considered that it was unlikely that a STFM for electricity derivatives would be actively traded on, and hence would not provide any investment signals or materially improve short term operational decisions, and thus was unlikely to generate any material benefit to consumers.

While voluntary ahead markets may find some limited and sporadic use, we do not expect that they would be broadly utilised. Electricity derivatives are typically available in quarterly or annual contracts and traded months to years ahead of dispatch; offtake or power purchase agreements operate over an even longer period. As the dispatch date approaches, more information is available to participants and there is less forecast variance between demand requirements and likely price. It therefore becomes less likely that parties have complementary risks and are able to agree a price. More detailed information on this argument is expanded upon in our submission to the STFM proposal.[6]

While AGL questions whether shorter-term derivatives will have adequate counterparties to deliver liquid products, we do not have concerns with these products being available to trade. These could be facilitated now or in the future through a central exchange if demand emerges.

We recognise that the ESB's proposal considers short-term contracts for both energy and services, in contrast to the STFM which was looking more directly at short-term energy contracts only. However, the

[5] See: https://www.aemc.gov.au/rule-changes/short-term-forward-market

[6] See: https://www.aemc.gov.au/sites/default/files/2019-05/Rule%20Change%20SubmissionERC0259%20-%20AGL%20-%2020190523.PDF

addition of essential system services to this proposal in our view does not seem to provide additional arguments for the development of ahead markets, and the same principles apply. For example, with reference to FCAS markets, AGL has previously offered FCAS hedges to the market, and there is no reason that a more established market for these products could be developed more broadly if there was sufficient demand.

Similarly, we expect that hedgeable products for operating reserve could also be developed, depending on demand and the structure of that proposed mechanism.

In our view, it seems even less likely that a short term market for frequency or reserves would be actively traded on, and hence would not provide any clear investment signals or materially improve short term operational decisions.

As described above, we do not consider that inertia and system strength lend themselves to the development of spot markets, although we are interested in understanding in more detail how the proposed UCS may facilitate the scheduling of these services.

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 consider that the UCS process may be an effective scheduling mechanism for the provision of inertia and system strength services, although more information is required to understand how these services will be procured prior to proceeding with UCS development. In our view, reserves and frequency are more appropriately procured through the existing spot market (i.e. a dynamic operating reserve and multiple frequency markets including FFR), for the reasons outlined previously.

However, we consider that significantly more work needs to be done to understand whether the outcomes claimed by the UCS could be met by more incremental improvements to the pre-dispatch and directions process, and whether or not a more complex scheduling tool such as the UCS would therefore provide substantial benefits.

The UCS process requires participants to provide bids for each defined system service and also economic cost and operating information. We note that the bidding process may not be effective at determining efficient market prices due to the local few-participant nature of these markets and because the markets may be prone to investment uncertainty due to network investment, consistent with the decentralised market provision of system strength outlined above.

Under the UCS mechanism the economic cost and operating information is designed to be used by AEMO to determine the least-cost out-of-market commitment should a security or reliability gap be identified. We consider that structures to determine appropriate compensation in this instance would share the same challenges as system strength directions; for example, accounting for opportunity costs, which can be highly variable, and accounting for scarcity, which is very difficult to determine for markets with few participants.

There is substantial detail required to be worked through in the UCS model; for example, the timescale of provision, regional and sub-regional characteristics, and compensation for generators providing services as a by-product of energy generation. Where generators are directed on to provide security services, compensation will increasingly need to take into account the long term costs of running the asset for the security service and not only short term costs of providing the by-product energy.

While we are supportive of the proposal to progress the UCS proposal for further consideration, we have some concern that the ESB is proposing already to *implement* the UCS. In our view, the UCS proposal must still be subject to a much greater level of technical development, and subject to a rigorous economic analysis to ensure that it meets the objectives of the NEO. For example, improvements to the pre-dispatch process should be considered instead of, or alongside, a UCS.

We look forward to providing more input into the development of a UCS mechanism through a more structured and detailed consultation process.

> The difference between actual and forecast residual demand leading up to real time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real time dispatch. What do you consider the drivers of this may be?

The way that available generation meets the amount of operational demand required depends on a number of short-term variables, notably, the available quantity of intermittent wind and solar generation. NEM marginal pricing also means that there can also be significant deviations in price from relatively small shifts in the demand forecast. This can result in occasional price volatility leading up to dispatch, which is useful in providing market signals to generators to ensure the market is clearing at the most efficient price based on the most up-to-date information. Where price volatility exacerbates risk, this encourages long-term contracting and hedging of the spot price, which can support new investment.

Spot price volatility can therefore be useful in providing a price signal for new flexible resources that are critical to the market, such as battery storage and demand response, which providing an incentive for longer-term contracting to underpin new investment in the market.

Section 8: Two-sided markets – Market Design Initiative E

> 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?

Improving visibility and participation of the demand side will be an important part of the future NEM. Demand response could help to defer investment in peaking generation that would otherwise only be needed for several hours a year, or avoid other costly market interventions. It could help to manage reliability concerns from unexpected changes in variable generation. Also, demand management (shifting) could contribute to system security and reliability by smoothing out variability in the system, to complement an increased update in DER. Addressing the “duck curve” is one example where customers could be rewarded for shifting their demand. If implemented in a cost-effective way, demand response could help to minimise overall system costs for customers.

We consider one of the main risks with moving towards a two-sided market is ensuring the rule and system changes to implement each step will deliver additional volumes of demand response and overall system value. AGL is in principle supportive of the ESB's proposed approach, which involves incremental steps to improve visibility and participation of demand side resources. Focusing on voluntary participation is the right approach at this stage. There will inevitably be some customers that are unable or not interested in demand participation or responding to price signals, particularly where it impacts their regular business operations. It will be important that these customers are able to choose their level of participation.

We are also supportive of an approach in which each transitional step is thoroughly and robustly assessed before committing to the reform. This enables the decision to be guided by the most up to date costs and benefits to ensure there is evidence for proceeding – clear evidence that the reform would unlock further volumes of demand response. Certain technology costs will need to reduce significantly to enable mass-market customer participation in scheduling. Data would need to be provided in near real time to support participation in a five-minute market.

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?

There are several barriers to demand response both generally and in participating in a centralised dispatch process.

As mentioned above, AGL considers the technical requirements currently required of central dispatch to be a significant barrier to participation in central dispatch. We expect that this workstream will investigate appropriate ways to reduce the technical requirements for participation of demand response. We also expect that technology costs will reduce over time to enable participation of more customer types.

Another key barrier is customer preference. In AGL's experience, customers want to maintain a choice about participation. Even where the demand response can be externally controlled, customers typically desire the ability to opt out. The forecasting and scheduling of demand side must recognise that customer priorities are fundamentally different to generation assets.

We have some concerns that the current direction of certain reforms may have unintended impacts on innovation and customer engagement. Specifically:

- Mandating the requirements for demand response enabled devices in AS 4755 (a legacy voluntary standard), with expanded functionality, may prevent new technologies and solutions from entering the market that would facilitate greater uptake. Given how much has changed in the last few years and that the expanded standard would be mandatory, we consider it may be more appropriate to develop a new standard. This could be developed with a similar approach to electric vehicles to achieve interoperability and support innovation – the "open point charging protocol" provides standard communications and a framework that can be adapted over time.
- Certain controls being imposed on customer DER, while attempting to address local network security issues, may have the unintended consequence of disengaging customers from energy markets. Reforms should look to establish more suitable ways to manage network congestion and voltage issues as a matter of urgency, and the restrictions imposed by networks and state governments should be wound back as soon as possible.

The current retail pricing limits and network tariff arrangements are also a significant barrier for small customer participation. These prevent retailers from offering innovative products and services for subsets of the market, and will prevent the wider engagement of small customer demand side.

Finally, customers may need to extract value from multiple streams to create incentives for participation and investment. In particular, current arrangements do not allow the full the value of network services to be monetised. This may restrain commercial investment in technology and it from achieving its full contribution to minimising costs in the broader system.

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

AGL is supportive of the near-term arrangements set out in the consultation paper, being:

1. Expand the aggregator framework (DER for energy and FCAS)
2. Investigate technical requirements for participation in central dispatch (telemetry, communications)
3. Better integrate storage devices, generator registration thresholds (rule changes)
4. Improved forecasting (build on experience from VPPs)
5. Improved visibility of price responsive demand loads

As mentioned above, we also consider it vital for the two-sided markets and DER workstreams that the different value streams are enabled. In particular, valuing network services and better constraint management.

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?

Customer participation will be encouraged through a two-sided markets framework that maintains customer choice and flexibility, and reforms that maximise the value of the customer’s actions or assets.

It will be important to ensure the consumer protections framework keeps up with the two-sided market design, particularly once small customer participation is enabled. Early discussions have suggested that aggregators would become the financially responsible market participant for the load they are managing. On one hand, certain loads may have a different levels of risk regarding whether they should be considered an “essential service”. On the other hand, it may be appropriate for certain consumer protections to apply regardless of the load, for example for vulnerable customers. We suggest that this should be carefully worked through once the pathway for a two-sided market is clearer.

What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?

AGL suggests developing a thorough understanding of the demand response capability that may be enticed to become price responsive load. This should include not only consulting with aggregators regarding their experience to date, but also a wide range of large customers who may not yet be participating in demand response programs. This would help to understand the true value of unlocking demand response for the NEM, and what might be needed to drive those customers.

The implementation costs and technological costs of customer participation will also need to be taken into account. Technology costs will come down over time, and so there will be a point at which taking the next step becomes cost effective.

> The ESB is considering combining the DER integration (below) and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?

Given the significant overlap between certain aspects of the DER and two-sided markets workstreams, AGL would be supportive of developing these together. It will be challenging to determine how to schedule, or increase visibility and participation of different types of demand response and DER. The capability of VPPs is fundamentally different to behavioral customer actions. Bringing these workstreams together could enable a more holistic approach to solving these issues.

Section 9: Valuing Demand Flexibility and Integrating DER – Market Design Initiative F

> Have any key considerations for the incorporation of DER into the market design not been covered here? For DER to participate in markets, it needs to be responsive. How should the Post-2025 project be thinking about enabling responsive DER?

AGL considers the integration of DER and demand flexibility to be one of the most important areas of reform. Distribution networks have not been built for two-way flow. Networks are managing the local impacts of DER through restrictions on output, or expensive building out of the network. Market arrangements should encourage innovation that coordinates and values the services provided by DER. Competitive arrangements with independent oversight will provide better outcomes for owners and customers more generally, through energy savings and autonomy, lower overall system costs, and greater engagement and participation.

DER integration is multi-faceted and will require reform and support across the following areas:

- **Market design** empowers consumers with choice to utilise DER for own comfort and to participate in a range of wholesale market and network services
- **Network regulation** encourages pricing, connection and market solutions that optimise network expenditure, access and competitive neutrality in the provision of network services

- **Technical standards** promote interoperability in device, communications and data protocols, and align with international standards to support an open and competitive market for DER
- **Government programs** support jurisdictional climate change goals and promote equitable access for all consumers; and industry trials test various market designs and promote innovative solutions
- **Consumer protections** promote consistent and transparent consumer experience and participation through fit-for-purpose outcome-focused regulatory framework

Market designs that provide a neutral environment for competition between different network and non-network solutions will be key to maximising the value of DER. We encourage the ESB to also look beyond the market design aspects of DER integration, and consider how it interacts with other reform areas as part of an integrated response. For example, the existing retail pricing limits and network tariff arrangements are not conducive to greater DER uptake and will need to be addressed with priority, to ensure holistic and effective DER integration.

The considerations set out in the consultation paper provide a good summary of the interactions with some of the other workstreams and the trade-offs that will need to be worked through:

1. *Delivering DER services through markets, or technical / regulatory processes*:
   AGL holds a strong preference towards markets that compensate customers for the services provided. However we appreciate there may be certain services where a technical solution is more cost effective for the overall system.
2. *Forecast DER participation rates*:
   AGL agrees that the expected uptake rates of different DER, and willingness of customers to participate, is an important consideration that should guide the market reform.
3. *Infrastructure for DER participation*:
   AGL agrees that significant upgrades to DER communications and back end systems will be required to fully integrate DER. A fundamental design shift may be required at some point in the future, informed by trials and when the cost benefit case is better understood. This should not prevent more immediate measures to value DER services and improve visibility where that is possible.
4. *Define categories and participation for DER and demand flexibility*:
   Applying generator obligations to DER and demand response would prevent many from participating. A balance needs to be found, where information provided by aggregators or scheduling by AEMO is credible enough for AEMO to securely manage the system, but without being prohibitive for the customer and aggregator.
5. *How far should DER integration go*:
   AGL considers that over the longer term, cooptimising DER services across different markets would be the ideal outcome. However, this may be a long way off due to the infrastructure requirements and current uptake levels. We support the ESB's more immediate objective of enabling DER to provide a range of energy and network services where this is cost effective. A key issue will be to set up institutional arrangements that ensure market innovation provides benefit to consumers through efficient integration and orchestration of DER.
6. *The potential for distribution level markets for energy*:
   Distribution level markets that enable energy trading and local settlement between buyers and sellers (peer to peer) is another possibility for the future. This will be supported by getting the right building blocks in place to allow for DER optimisation - setting up the broader institutional and market framework to allow for progressive arrangements that allow maximum value to be created and shared between customers and the network. This is likely to involve independent distribution market operators to provide for maximum contestability and encourage innovation. Market

arrangements may begin with more direct ways of remunerating DER services (network services, FCAS and wholesale participation) and evolve over time to more sophisticated distribution level solutions (overseen by market operators).

In the next phase of the project, the ESB proposes focusing on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? We are considering combining the DER integration and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done

AGL is supportive of the ESB developing a market integration proposal in the next stage of this review. The immediate foundational measures will help to set up DER for future participation, while addressing some of the immediate concerns around DER visibility, standards and interoperability. We consider the following reforms to be fundamental building blocks that will enable more sophisticated DER markets to evolve:

- Appropriate technical standards
- Well established and functional governance arrangements that allow for competitively neutral solutions to be found for distribution system issues
- Open and transparent low-voltage network data to set operating envelopes
- market arrangements that support competitive procurement and customer choice for orchestration services
- Network tariff reform
- Fit for purpose consumer protections

The unlocking of network value is one of the most important priorities for DER integration. This will avoid the current path of placing restrictions on the installation or output of assets, which is negatively impacting customers. Unlocking the locational network benefits of DER will benefit all customers, instead of capital expenditure that is borne for years by customers. The market needs to determine the value that DER can provide to networks and develop mechanisms for signaling and remunerating those services. We understand this work is underway though some trials and should be prioritised. This is likely to involve independent distribution market operator arrangements.

DER should be included in providing any new security services, where technically feasible. We consider the provision of local network and security services might be the most valuable contribution from DER over the short and medium term, with regard to system impacts and avoided costs.

It may also be helpful for the ESB to identify the main hurdles or decision points that will guide industry to any other key trials that may be needed over the next 5 years, to inform whether and when to take the next steps.

As noted above, AGL sees the value in progressing aspects of the two-sided markets and DER workstreams together, given the close interactions.

How can we ensure owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?

Establishing incentives and market arrangements to value the services provided by DER will be vital. In the first instance this may involve incremental or low-cost steps that enable the services to be valued. A more fundamental shift in market design may be necessary to properly transition over the longer term to markets for network services (at the distribution level) and integrate those services with the NEM. All of these steps should be informed by trials to test innovative methods and determine the value and costs involved.

Section 10: Transmission Access and the Coordination of Generation and Transmission– Market Design Initiative G

The Integrated System Plan is now in its second year. Do you have any comments on how its implementation can be made more efficient and timely?

The Integrated System Plan (ISP) provides a useful analysis of 'whole-of-system' development pathways to respond to a range of long-term future energy market scenarios. As the ISP represents potential development pathways against a range of very diverse scenarios, it remains important that investment in proposed developments, particularly regulated infrastructure, meets rigorous economic evaluation prior to approval, to ensure it provides the most value to customers over time.

We are supportive of the improved methodologies employed by AEMO in its development of the ISP and there are substantial improvements from the previous NTNDP. These improved methodologies have identified that there are lagging transmission projects, which have resulted in increased congestion and decreased system strength throughout parts of the network as a large amount of VRE has connected in recent years. The ISP has provided a useful overview of where transmission developments need to occur to remediate potential shortfalls in inertia and system strength, as well as provide an overview of prospective transmission development that may unlock future areas of renewable development (i.e. REZs).

However, it is important to note that methodologies employed by AEMO to formulate development pathways under the ISP consider 'whole of system costs', with only a small range of sensitivities considered. Simply put, this means that the individual costs and benefits of a specific transmission project are not assessed on a standalone basis, but rather in the context of the broader development pathway, which includes assumed build of other projects, including new generation.

While this is a sensible planning approach, it suggests that further economic analysis of component projects is critical before approval, as actual development pathways are likely to deviate from AEMO's diverse range of scenarios. In cases where complementary projects that are critical to meet benefits are not also developed, there is a risk that proposals put forward by the ISP will not meet their stated benefits.

This need for further economic assessment of proposed network projects is increasingly critical as the ISP has gained status beyond a simple planning document. The ISP has also become an increasingly important document to inform government policy, and also has the ability alter the approvals process for a proposed development. For example, identification of a project as a Group 1 project under the ISP results in that project progressing to an advanced stage of the RIT-T process.

We therefore consider that a degree of caution must be exercised in ‘actioning’ the ISP, and we do not consider that a general planning document should be generally implemented without substantial consideration of the individual merits of each development within that project.

For example, while the ISP has supported some network projects on the basis of initial cost estimates, as those projects have progressed through a more robust RIT-T process, there have been substantial deviations from initial forecasts used to inform the ISP.

These material changes in costs and benefits warrant closer examination by the AER to ensure that the long-term interests of consumers are being assessed accurately. This may include a reassessment of a RIT-T where cost estimates materially change, and a recognition by AEMO when preparing its ISP that recommended transmission investment pathways should only be identified and proceed where they represent cost-efficient transmission expenditure and where individual projects are likely to stand up on their own merits.

As part of its strategy and implementation of the ISP process, the ESB and AEMO should consider how it reflects ISP ‘actionable’ projects in future versions of the Integrated System Plan to ensure that the needs of the system are balanced with the risks and costs associated with new investments.

In summary, we consider that the allocation of capital for generation investment must continue to be driven by competitive businesses who are making their own forecast assessment of market risk, rather than by central forecasts. Regulated infrastructure, while requiring a degree of central planning based on longer-term forecasts, must be subject to rigorous cost benefit analysis to ensure it supports the deployment of private capital to fund generation projects at the lowest overall cost to customers.

The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?

The cost of major transmission projects remains uncertain until detailed assessment of those projects has been undertaken through the RIT-T process. In our view, costs have regularly been underestimated at early stages of approvals, only to be subject to price increases at latter stages of approval as more detailed information is provided.

A clear example is ElectraNet’s recent Energy Connect transmission project, which was approved in February 2020 on the basis of a cost of $1.53bn and $269m of stated benefits. In August 2020, and before development has even commenced, ElectraNet have informed the market that an updated cost is likely to be in a range of $2.2-2.4bn.

These regular increases in transmission costs led AEMO to increase to costs associated with transmission projects by 30% from its draft 2020 ISP to the final document. Even so, we expect that that the costs associated with many transmission projects are likely to exceed estimates, and there we consider they should be subject to careful economic scrutiny via the RIT-T to ensure benefits over the life of the asset.

Practical steps to improve the accuracy of transmission project costs could include the requirement for TNSPs to more accurately input into AEMO's ISP assessment framework, including limiting the technical design specifications of a project; for example, locking this down to a few options to provide a cost-reflective range, and then linking this to the AER's Service Target Performance Incentive Scheme (STPIS) framework to ensure suitable incentives are placed on TNSPs. These same project specifications could then be utilised by the AER via the RIT-T process. Having more similar specifications assessed under ISP and RIT-T would improve the accuracy of the ISP and reduce the likelihood of material cost and benefit fluctuations as projects reach advanced stages of approval.

The development of Renewable Energy Zones is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?

The ESB's proposed interim REZ framework, currently under consultation, provides a valuable opportunity to assess the issues associated with REZ development. AGL has provided a submission outlining its assessment of that proposed process.[7]

REZs, by design, involve bespoke jurisdictional policy arrangements. This is appropriate, as large-scale developments need to take account of State-based policies. REZs are also likely to contribute to State-based climate policies as well as serve other purposes relating to jobs and economic growth, especially in regional areas.

Any framework must recognise that REZ deployment more than efficient transmission development, but also a part of a broader planning process that incorporates wider regional planning, consideration of job and cross-sector industry development, other infrastructure requirements, and environmental management issues.

The assessment of each REZ is therefore likely to require different considerations, and there may be different opportunities depending on the planned generation development within that area. Nevertheless, as REZ's link into an integrated NEM grid their development also needs to be guided by the National Energy Objective. As a general principle, we consider that while there may be a number of different ways of allocating risk over project life, these approaches must ultimately benefit consumers, and not introduce excessive risk for existing assets.

Indeed, linking REZ access protection to a joint (regulated and private) funding model could assist in lowering the costs of infrastructure build by providing incentives and security to private sector investors. As above, the regulated investment component should be assessed under the RIT-T and linked to the STPIS to encourage efficient, timely investment.

[7] See: https://thehub.agl.com.au/-/media/thehub/documents-and-submissions/2020/agl-response-to-consultation-paper-and-draft-rules-interim-rez-framework.pdf?la=en&hash=01A5F6933F1FD37389984AC2171D0CAC

We have some concern that all interim REZ models being considered by the ESB and State Governments are fully regulated models, and it is not entirely clear within the interim proposal as to why a private sector funding model is not at least being considered among the range of potential funding options.

We look forward to providing further input into various deployment options for REZs through the development of the ESB's interim REZ framework and the practical example of REZs that are currently being developed, notable the Central-West REZ in NSW. These practical examples will highlight issues with broader scale REZ deployment.

NERA Economic Consulting's modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit for purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs what other suggestions would you make about how risks of congestion might be managed by generators?

The NERA modelling suggests that transmission access reform will provide very substantial benefits for customers over time. We consider a relatively good case has been put forward by the AEMC and NERA that LMP and FTRs could provide a benefit to customers over the long term, and therefore we consider that further investigation as to how these mechanisms could work in a NEM context is justified.

While we support further consideration of these reforms on the basis of these stated benefits, we submit that benefits would need to be significant to justify such a significant reform in the market, and that more work needs to be done to establish the merits of such a major transition, especially in the context of other more critical reforms that may be required.

While we generally agree with the premise that marginal pricing should increase efficiency in overall investment, we consider that the NERA analysis significant overstates these benefits, and therefore does not serve as an accurate assessment of the cost and benefits of the introduction of LMP and FTR in the NEM.

In our view, investors are likely to avoid connection locations subject to congestion, especially if it is already known to exist or could have the potential to exist through future modelling. This is particularly the case given the increased risk profile of loss factors for investors when compared to a decade ago. In our view, the NERA analysis significantly underestimates the ability for project developers to identify suitable locations in the grid where the risk of congestion is lower.

Moreover, while the general modelling approach used by NERA is adequate in determining the subsidy and the potential change in build, we are concerned that a single iteration of the process is unlikely to lead to an outcome close to the equilibrium. Based on internal modelling, AGL believes that the subsidy can decrease rapidly with increased generation capacity and the approach taken by NERA will not adequately demonstrate this effect

More detail on AGL's rationale for this position is included in AGL's submission to the AEMC's Transmission Access Reform Interim Report.

The range of uncertainty captured by this modelling task highlights the need for careful scrutiny and a gradual implementation of reforms. In our view, the case has not been established for an urgent implementation of LMP and FTRs, and indeed the benefits of a careful and smooth transition over time (e.g. taking steps such as long notice periods and appropriate grandfathering of contracts) may be eroded by a rushed implementation.

> The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?

We agree that locational marginal pricing and financial transmission rights present a workable solution to addressing some issues with access reform and commend the work that has been done by the AEMC to progress the potential applicability of this solution to the NEM. More information regarding AGL's position on the proposed suite of access reforms is included in AGL's submission to the AEMC's Transmission Access Reform Interim Report.

We consider that these reforms should be integrated with other market design elements, and carefully sequenced to minimise the costs of the considerable system development required. Locational network pricing and financial transmission rights will need to integrate and follow other new price signals involving resource adequacy or system services. This would require slowing the AEMC's review process so it can be considered with the full package in mid-2021.

At the same time, to begin to address other challenges associated with coordinating transmission and generation build, we support further consideration of practical lessons from initial REZs that are being developed, to better understand opportunities to improve this coordination on a broader scale.

As a general point, we note that coordinating generation build will remain challenging while long-term signals for investment remain uncertain. Concerns pertaining to access reform may depend more broadly on steps to address other objectives such as meeting reliability and decarbonisation objectives.

> What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.

The past decade has seen significant investment in subsidised generation capacity in the NEM, much of which has not been efficiently located based on available network capacity. This hurried entry into the market has led to lower than forecast generation output from many of these projects. Generally, this has not been a failure of new entrant generators, but rather the absence of adequate mechanisms to ensure new investment is well located.

Increased understanding regarding the congestion risk of poorly located investment, combined with the Integrated System Plan and Renewable Energy Zones is likely to significantly improve this problem. The introduction of Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTR) in theory could further improve the efficient location of new investment in the NEM.

A more detailed response to issues under consultation is provided in AGL's submission to the AEMC's Transmission Access Reform Interim Report.