AGL Energy Limited
T 02 9921 2999
F 02 9921 2552
agl.com.au
ABN: 74 115 061 375

Level 24, 200 George St
Sydney NSW 2000
Locked Bag 1837
St Leonards NSW 2065

Dr Kerry Schott

Chair, Energy Security Board

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Delivering affordability and flexibility to support Australia's energy transition

AGL understands the importance of the energy sector to Australia's broader economy and the need to decarbonise the energy sector and reduce Australia's emissions. 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 to meet the challenges of the important energy transition that is underway.

The COVID pandemic has disrupted the Australian economy like no event before, and it is vital to ensure energy remains affordable to allow Australia's economy recover as speedily as possible. At the same time, Australians are increasingly concerned about the impacts of climate change, and policy action to reflect this growing concern will likely accelerate the energy transition.

While the pandemic has provided impetus for Governments to reconsider energy policy and consider short-term stimulus that may yield longer-term benefits, the Australian economy is forecast to be in a period of low growth for a number of years. Household living and business expenses, including the cost of energy, will therefore remain significant ongoing concerns. As further steps are taken to accelerate the energy transition, long-term benefits and costs to both customers and the broader Australian economy should therefore be at the forefront of the rationale for reform.

> *To maximise the benefits of the energy transition, the right balance needs to be struck between developing incentives to support new investment while rewarding the ongoing value that can be derived from existing energy infrastructure and aging assets to achieve the best outcomes for energy customers.*

Anticipating trends in customer needs, community expectations, and emerging technologies

The acceleration of the energy transition will continue to be guided by evolving trends in customer needs, community expectations, and emerging technologies.

Customers will continue to seek affordable energy prices but will be increasingly interested in greater choice about their own energy production and consumption, as well as reducing their carbon footprint.

Community attitudes will continue to influence public policy choices around reliability standards and sustainability, and cost trade-offs associated with these.

New technologies will drive down costs of new forms of low-emissions energy and storage, leading to a system characterised by greater distribution, variability, and flexibility.

> *While these evolving trends present enormous opportunities to benefit consumers and reduce emissions, the changing energy mix will require complementary adjustments to maintain grid reliability and stability, as well as a clear direction for the deployment of hundreds of billions of dollars of private capital over coming decades.*

Within this environment, proposals to accelerate the energy transition are prudent and likely to deliver benefits to customers. However, governments must also be cautious about longer-term expenses as well as ongoing costs to taxpayers and energy customers.

Reforms to guide and accelerate the energy transition should therefore maximise shared value between businesses and customers, leverage private sector investment, and support Australia's economy by minimising household energy expenses and long-term fiscal exposures of Governments. While reforms should incentivise investment in new energy resources, they must also retain value in existing assets to deliver the best outcomes for energy customers and Australia's economy.

> *The ESB Post-2025 reforms must support Australia's economic recovery from the pandemic by focussing on practical steps to minimise the costs of the energy transition, leveraging private sector investment, and maximising shared value between businesses and customers.*

Principles for reform

Reforms to achieve these objectives would be well guided by adherence to some fundamental principles, many of which have been well considered in the ESB's Options Paper:

- Focussing on **meeting the needs of energy consumers** including their need for reliable and secure energy supply at an affordable price but also growing desire to participate directly in the energy transition.
- Driving reforms that **support the energy transition** by strengthening signals for private sector capital to meet emissions reduction targets and ensuring the security and reliability of the grid at the lowest price.
- Developing a consistent **whole of market solution** (i.e., across all States and jurisdictions) to improve market efficiency, provide greater certainty for private sector investment, and deliver overall lower costs for customers.
- Avoiding **continued fragmentation** of the market by enabling jurisdictional policies to be met by a nationally consistent market structure.
- Establishing clear **signals for new investment** to enable further deployment of private sector investment to enable the energy transition and minimise risks to taxpayers and energy customers.
- Structuring reforms and incentives to retain the **value of existing generation and energy infrastructure** to the overall system.
- Meeting **security and reliability objectives at lowest cost** by utilising the broadest range of assets.
- Supporting an **orderly transition** while recognising the policy imperatives associated with the closure of thermal plant.
- Implementing reforms on an **appropriate timeframe** that is commensurate with the scale and importance of the reform, which could range from immediate action up to a number of years in the future.

Current market challenges

Over the next two decades, a massive amount of new large-scale renewable generation and distributed solar generation are forecast to be connected to the NEM. Forecasts suggest that around 26–50 GW of new large-scale wind and solar and 13–24 GW of distributed PV are forecast to come online, which will require 6–19 GW of new utility scale, flexible and dispatchable resources, as up to 63% of the current thermal fleet in the NEM retires by 2040.[1]

State based policies aimed at meeting emissions reduction targets and climate commitments are accelerating the uptake of variable renewable generation. In NSW, the Electricity Infrastructure Roadmap will see contracting with 12 GW of new VRE over the next decade, and in Victoria, the Renewable Energy Target to achieve 50% generation from renewable sources by 2030 is being achieved through reverse auctions.

While wind and solar are the cheapest form of new generation, it is important to recognise that the very rapid entry of new generation is as a result of subsidised generation that would not otherwise be built based on expected spot market revenues within the current market design.

As a consequence, subsidised investment is placing downward pressure on energy spot prices and contract prices, weakening market signals for new investment and capex spending on existing generation. This is also increasing the pressure on existing generation to exit the market.

> *While it would be preferable to use efficient market mechanisms and reforms to the existing design of NEM in order to respond to challenges presented by the energy transition, it must be recognised that it is no longer politically acceptable for investment to be driven by the cyclical high price periods that support longer-term hedging arrangements and contracting. Eventually, adjustments based on the existing structure of the NEM may therefore not be sufficient to overcome some of the distortionary impacts from this magnitude of subsidised generation.*

This is not to say that the fundamental energy-only design of the market NEM is not currently fit for purpose, as has been alleged at times throughout the ESB's reform process. Indeed, we consider that the energy-only structure of the NEM has proved remarkably resilient at accommodating a range of changing policy objectives, and it remains a useful basis from which to manage early impacts from the transition. Currently, reliability forecasts are relatively positive, wholesale prices are low, and record amounts of low-emissions generation are being connected to the grid.

At the same time, continued interventions and utilisation of out-of-market subsidies place increasing pressure on the energy-only structure of the NEM to be able to provide the right investment signals that are needed to support the market through the transition.

Over time, the continued departure from using the NEM spot price as a fundamental driver for new investment may therefore necessitate more substantial changes from the existing architecture of the NEM, including additional markets that value attributes other than energy.

While such an approach is likely to involve transitional cost, structural changes as to how generation recovers costs may eventually need to be considered in order to both manage the orderly closure of plant and incentivise investment in efficient levels of dispatchable generation in the future. This may be required to allow the pace of the energy transition to accelerate without adverse consequences to customers in terms of price and reliability outcomes.

Practical steps to minimise the costs of the energy transition and maximise shared value between businesses and customers

[1] AEMO, 2020 Integrated System Plan

Key to the development of a coherent and achievable reform program are proposals that ensure affordable and reliable power during Australia's energy transition. This requires not only adequate supply in the short-term, but robust structures to maintain reliability and security and clear guideposts for the very substantial private sector investment that is required within Australia's energy sector over the next few decades.

This can be achieved with a package centred around the following priorities:

1. **flexible approaches to retaining value from aging thermal plants** by not restricting options for plant operation prior to exit.
2. **development of a dynamic operating reserve** to provide additional incentives for dispatchable power and certainty about system reliability.
3. **new competitive market frameworks for distributed energy resources (DER)** to maximise customer participation in the energy transition and drive private investment in energy infrastructure that provides shared value to businesses, DER owners, and the broader community.
4. **development of new markets for essential security services** to maintain the security of the grid with a changing generation mix.
5. **efficient build and use of transmission infrastructure** to enable new Renewable Energy Zones (REZ) at minimal cost to customers.

1. Flexible approaches to retaining value from aging thermal plants by not restricting options for plant operation prior to exit

Throughout the energy transition, it will be important to balance any incentives for new generation with the value to customers that is provided by existing plant, and especially existing low-cost thermal generation, which provides both bulk energy and essential system services.

As the ESB has identified, reforms that seek to accelerate the transition, such as jurisdictional schemes to increase the uptake of large-scale wind and solar, may have unanticipated consequences if they bring forward thermal asset closure dates without adequate time for the market to adjust. As a result, consideration of conditions surrounding generator exit are prudent measures to consider.

However, some of the measures proposed in the Options Paper, such as seeking to restrict a generator's choice to operate in a more efficient way prior to closure, go beyond prudent backstops and may have the effect of creating more risk for participants rather than removing risk from the market. This will likely increase costs for customers and exacerbate challenges with orderly closures.

During the energy transition, we expect that the market will be subject to operational challenges and generators should continue to operate to the highest levels of compliance with regulatory obligations as they do now. At the same time, efficient operation of aging plant (whether that be through efficiency upgrades, lower minimum generation levels, two-shifting, seasonal shutdowns, or mothballing) will be critical to the efficient operation of the market during the transition.

> *Steps to limit these options by imposing restrictions on plant operation are therefore concerning. Limiting efficient options for thermal plant operation by seeking to impose an exemptions or approvals regime may have the effect of increasing costs to customers, bringing forward closure dates, raising health and safety concerns, and disrupting the energy transition.*

In an environment of lower wholesale prices, restrictions on generators from choosing to not run where they may incur a financial loss carry a real risk of bringing forward closure dates and bringing forward precisely the type of early and disorderly closure that these reforms are seeking to avoid.

2. Development of a dynamic operating reserve to provide additional incentives for dispatchable power and certainty about system reliability

System reliability must be maintained at the lowest cost to customers, and in a way that takes into account the different perspectives that governments have on what constitutes adequate resource adequacy in a modern electricity system.

While historically the NEM Reliability Standard of meeting 99.998% of energy needs has been met in almost every year since market start, it is clear that expectations about resource adequacy are changing, and there is at least a perceived greater risk of capacity shortfalls both over longer periods and as a result of high-impact low-probability 'tail' events.

This has led to a desire to have more 'spare' capacity available in the NEM than has previously been incentivised, which has led to practical impacts such as procurement of greater volumes of AEMO's emergency reserve mechanism (RERT), pressure to keep aging thermal plant open beyond announced closure dates, and substantial public subsidies in new dispatchable generation.

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, as well as developing interim and alternative reliability targets, which have been used as a basis for policy interventions outside of the market.

> *While there is not currently clear evidence of a generalised 'missing market' for resource adequacy into the future, there is therefore clear evidence of a gap between the operation of the current NEM and government expectations of the quantity of available dispatchable generation capacity into the future.*

Indeed, the ESB is responding to this trend and has proposed several modifications to the RRO to incentivise greater amounts of available capacity without changing the structure of the existing spot market. These measures are aimed at providing additional incentives to build dispatchable capacity over time.

However, we do not consider that a sufficiently strong case has been made to rapidly progress either the proposed changes to the RRO or to development a market for physical generation certificates (i.e., the Physical RRO) at this time, especially as both of these mechanisms are based on reliability forecasts, which are relatively positive at the moment.

A fundamental challenge with the current RRO is that is seeks to impose higher levels of contracting in the absence of market signals (i.e., higher prices) for those contracts. The intent of the mechanism is therefore for new generation to be built on the basis of a compliance obligation rather than a market signal for new capacity. Modifications to the design may not be able to overcome this fundamental flaw.

With regard to the proposed Physical RRO, we consider that much more work needs to be undertaken to consider options for long-term capacity incentives, whether they are centralised or decentralised capacity payments or a proxy for that payment through a retailer-led market for capacity certificates.

With the current lack of information on how the Physical RRO would be structured and resulting impacts on generation revenues, the proposal remains at a conceptual stage. However, as noted earlier this submission, steps to more directly incentivise dispatchable plant through capacity mechanisms may need to be considered in the future if wholesale prices continue to be suppressed by subsidised variable renewable generation.

> *As an alternate course of action, a much more pragmatic and no-regrets option could be to establish a dynamic operating reserve to ensure a minimum amount of dispatchable generation is always available in reserve, while keeping a watching brief on the need for a more direct incentive for dispatchable capacity in the future.*

While the operating reserve in the ESB Options Paper has mostly been positioned as an essential system service to respond to rare system events, in our view it has a much more prominent role in incentivising dispatchable capacity to levels that are set by governments in accordance with their own energy sector objectives.

In our model, which has been discussed with the ESB, a dynamic operating reserve is procured in addition to the capacity needed to meet operational demand. The reserve is procured not only in accordance with the needs of the system at the time but also the requirements of governments to meet longer-term policy objectives. For example, in the detailed design of a dynamic operating reserve, governments could choose to set higher reserve margins (e.g., procure more reserve to a different standard) or limit the types of generation that could bid into the reserve to meet jurisdictional dispatchable or renewable generation targets.

> *AGL modelling suggests that a dynamic operating reserve, structured correctly, would be the least cost way of procuring additional dispatchable capacity to meet jurisdictional energy policies and a higher standard of reliability over time.*

A dynamic operating reserve structured in this way ensures that there is always additional capacity available at short notice, which ensures higher levels of reliability are met with minimum intervention to the current NEM model. The reserve would also provide some additional revenue for dispatchable capacity at minimum cost to customers compared to other proposed reforms. Further information on this option is included in Appendix A.

3. New competitive market frameworks for the procurement of distributed energy resources (DER) services to maximise customer participation in the energy transition, and drive private investment in energy infrastructure that provides shared value to businesses, DER owners, and the broader community

Accelerations in the uptake of Distributed Energy Resources (DER) have exceeded all but the most bullish forecasts, and we expect that this trend will continue, especially with reductions in the cost of household batteries and as electric vehicles become a more compelling proposition for households in years to come.

DER and demand response will have a key role in maintaining reliability and minimising both system and consumer costs. Both can provide flexible energy sources to shift and flatten load and provide alternative ways of meeting peak demand, contribute to reducing network costs through introducing competition, and provide alternatives to network solutions. Given the prominence of network costs in terms of overall customer energy costs, putting in place the right market arrangements will facilitate the transition while maintaining affordability for customers.

DER and demand response will contribute over time to addressing some of the problems identified under other market design initiatives, particularly resource adequacy and essential system services. 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.

> *Approaches to reform should maximise shared value between customers and businesses, driving efficient investment in resources that support customers without impacting on the broader grid. This points towards delivery of products and services by the competitive market; DER control and operation must be led by competitive businesses on behalf of customers to maximise uptake, innovation in products and services, and shared value.*

There is strong potential for whole-of-system cost savings to be realised through the integration of DER and the associated value streams that can be provided by the orchestration of DER assets. By establishing effective competitive arrangements for the procurement of system security and network services, DER has potential to substitute expensive network build, deliver value to owners and broader consumers, and provide alternative ways of meeting system security requirements. Over time, electric vehicles will play an increasingly important role in the energy system, so market reform here has significance for the transport sector and its own energy transition.

Over the longer term, consumers and communities will increasingly expect greater autonomy, 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 to support customer value while maintaining system reliability and security.

The development of new competitive market frameworks for DER should be aimed at delivering least cost solutions that maximise value for DER asset owners and energy consumers more broadly. Accordingly, the near-term approach should leverage existing market arrangements rather than creating additional complexity through alternative trading arrangements. While the multiple trader model promises increased competition in the delivery of different aggregation services, it does not guarantee greater efficiency for the individual customer vis-a-vis orchestration of their asset. To facilitate the scaling of DER towards market share equivalent to large-scale generation, we would also support establishing scheduled 'lite' arrangements that provide equivalent obligations on aggregators as apply to other market participants, though the method of scheduling may differ.

The maturity plan should also provide clear direction and timeframes for the development of the following supporting measures for the development of a more mature market for DER services:

- **Fit-for-purpose consumer protections and retail authorisation** framework for DER service providers, implementing the recommendations of the AEMC in its 2019 Consumer Protections Review;
- **Effective network economic regulation** to ensure networks compete in the contestable market on an equal footing to prevent cross-subsidisation and potential consumer harm, including through strengthened ring-fencing arrangements to prevent direct investment in battery storage;
- **Network access and pricing arrangements** to support efficient planning and investment for export services whilst also addressing equity concerns in non-DER customers' cross-subsidisation of DER customers' use of the distribution network;
- **Clear parameters on investment in 'community' distribution level storage assets** to ensure monopoly network businesses do not displace the competitive market for DER services, that is better placed to facilitate co-optimisation between the multiple value streams that adhere to energy storage;
- **Appropriate governance arrangements for DER Technical Standards** through the forthcoming DER Technical Standards Governance Review, including mandatory consumer cost benefit analysis;
- **Improved deployment of advanced metering arrangements** to enable the market to scale, following the AEMC competitive metering arrangements review;
- **Establish an effective national connections framework** to support consistent consumer outcomes in the transition toward dynamic connection agreements; and
- **A national program to develop interoperability standards** to support market integration and customer choice.

To manage the emerging system security challenge of minimum demand, interim emergency backstop arrangements may need to be established that can be superseded with market-based solutions as investment in smart inverters and energy storage solutions scales. As far as possible, any interim measures recommended through the maturity plan should draw upon existing market arrangements and provide clear safeguards on the limits of control as well as visibility on the impact to customers. The maturity plan should also articulate a clear pathway towards a market-based solution to mitigate impact to customers, through the development of appropriate market signals to shape consumer energy use as well as incentives to accelerate investment in supporting technologies.

4. Development of new markets for essential security services to maintain the security of the grid with a changing generation mix

The direction of the ESB's Essential System Services reform pathway is relatively clear, and it is broadly accepted that new markets for services need to be established to underpin provision of essential system services through the transition. The Options Paper clearly makes the case that there are missing markets for essential services like frequency control, inertia, and system strength.

Recognition of the value in these services is critical to moving away from current framework where generators are compelled to maintain system security (both through connection arrangements and ongoing directions and interventions) and incur costs for doing so.

> *Failure to properly incentivise these services will lead to increasingly costly directions and interventions to achieve system security, which will impact on the efficiency of the dispatch of the generation fleet, risk delaying the pace of the energy transition, and ultimately lead to higher costs for customers.*

We broadly agree with the proposed framework for gradually introducing market signals over time to allow the market 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, virtual power plants, and other new technologies will be better placed to provide services, facilitating the transition over time.

The ESB's direction of proposed reform regarding scheduling and ahead markets also seems relatively sensible. We agree that mandatory ahead markets are not warranted and would impose significant transition costs for little benefit in terms of system security. Conversely, a relatively good case has been made for the provision of improved information about unit commitment to the market operator, and further explorations and development of the proposed Unit Commitment for Security (UCS) are justified. Further information concerning these issues in included in Appendix A.

5. Efficient build and use of transmission infrastructure to enable new Renewable Energy Zones (REZ) at minimal cost to customers

The energy transition will involve, under all scenarios, a significant growth in renewable generation that has a very different geographic distribution than today's energy infrastructure. 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. At the same time, reforms must seek not to disadvantage existing generation assets, while also taking advantage of major transmission infrastructure surrounding existing thermal assets.*

The past decade has seen significant investment in new generation capacity in the NEM much of which has not been efficiently located based on network capacity, which has led to reduced output from these generators. 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, including improved access to system information due to the Transparency of new projects rule change, combined with the Integrated System Plan and Renewable Energy Zones are likely to significantly improve this problem.

The introduction of Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) in theory could further improve the efficient location of new investment in the NEM. However, AGL considers that whether LMP and FTRs in the NEM are required and will be cost effective remains an open question.

The ESB has responded to opposition on the timeframes for implementation of CoGATI by seeking to implement an interim solution, versions of which are outlined in the Options Paper. In our view, there seems be no compelling case to develop an interim transmission access model – if, as it states, the ESB's preferred model is to eventually move to CoGATI, we consider that it would be more preferable to wait until after the NEM 2025 recommendations are implemented before continuing work on any new access regime instead of directing resources towards and interim model.

Customer and community confidence that costs are being minimised will be a key driver of sustainable change

Regulatory and government intervention remains a major risk to a smooth energy transition. As we have seen in recent years, there is no shortage of private capital that is willing to be deployed throughout the Australian energy sector, particularly in small- and large-scale renewable assets, but also in dispatchable technologies such as gas, hydro, and batteries.

> *The challenge for the ESB remains how to limit the risk of future intervention and maximise the ability for businesses to invest in the energy infrastructure that will be required over the coming decades.*

In our view, many of the reforms show a great deal of promise in helping to develop structures around which the energy transition can be more carefully managed. Among these, steps to improve system security and operational challenges associated with a new generation mix are particularly promising. Significant advances have also been made in stapes to develop Renewable Energy Zones (REZ) and investigate generator access schemes to improve coordination with necessary transmission build. However, we recognise that this approach will take some time to settle, and for governments, communities and the market to be confident of progress that has been made.

The areas where most uncertainty remains are in the areas of DER and resource adequacy, where conflicting views on fundamental characteristics and risks within the energy transition have created an intensely contested environment for reform.

Embarking on major reforms in either of these two areas is a substantial undertaking, which is likely to require a level of understanding from customers, industry, and policymakers. In our view, the Options Paper does not adequately set out a compelling case for immediate reforms in either area that are justified under the objectives of the 2025 Project, although we hope that this will be investigated more thoroughly through the next stage of the program where benefits of reforms are evaluated against the status quo.

Of the two areas, we are more supportive of the approach taken by the DER workstream, where a maturity plan with a staged approach has been developed to look at evolution over time in an incremental way. There may be merit to a similar approach to be taken in terms of resource adequacy, especially as there appears to be no immediate risk of major capacity shortfalls in the next few years.

Where no market mechanism or consistent approach to reform can be agreed upon, we note that it may be the case that Governments need to continue to act in a pragmatic manner by addressing market failures in a more reactive fashion to meet jurisdictional objectives. While this outcome by no means reflects an efficient outcome, recent evidence highlights major challenges in implementing energy reform packages that are robust enough to withstand pressures from divergent government policies. Where these differences are too great to overcome, policy should seek to minimise divergencies rather than implement sub-optimal reforms that do not dissuade further interventions.

It is therefore critical that the next phase of reforms must focus on empirical evidence of net benefits and costs of reform direction and particularly the interactions between the various initiatives under different scenarios to understand not only costs of reforms but benefits from limiting future intervention.

Further detail in response to each of the questions raised by the ESB in its Options Paper is included at Appendix A to this submission.

If you have any queries about this submission, please contact Aleks Smits (Senior Manager Policy) at ASmits@agl.com.au.

Yours sincerely,

Elizabeth Molyneux

General Manager Policy and Markets Regulation, AGL Energy

Appendix A – Responses to Questions in the Options Paper

The questions raised in the Options Paper are expansive and consider complex and detailed issues.

Brief responses and general positions are provided in this Appendix, but many of the issues raised will necessitate further detailed consultation.

Part A

Chapter 2 - Resource Adequacy Mechanisms

A1 *What types of information provision regarding jurisdictional investment schemes would benefit participants the most?*

Expressing key scheme attributes consistently would be helpful in providing certainty to investors and understanding interactions with other schemes, for example:

- Size of targets expressed clearly and as a consistent measure of MW, MWh, % of demand, or % of capacity, and treatment of interregional and large- or small-scale generation in its contribution to any scheme;
- Detail concerning technology or project exclusions such as limitations on technology type or size;
- Any locational expectations and coordination with existing or new transmission projects;
- Expectations of project development and emissions reduction target timings including development pathways or gateway targets; and
- Financial characteristics such as the utilisation or of existing market structures (e.g., the NEM spot market), or derogations from existing market rules.

A2 *Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?*

The structure of current subsidies for new generation has the effect of suppressing wholesale prices and affecting the clarity of market signals in the NEM spot market for new unsubsidised investment of all generation types. As much as possible, new jurisdictional investment schemes should seek to preserve existing NEM arrangements or consider rebalancing incentives for unsubsidised generation; for example, improving revenue potential for critical flexible and dispatchable generation through the development of new markets that value dispatchability and essential system services.

Support for generation under jurisdictional schemes be structured in a way that ensures subsidised generation to continue to participate in the spot market and contract market; for example, there should be incentives to be available at high price periods and to reduce output at periods of negative pricing, and to offer derivative contracts into the market to manage these exposures.

Subsidised capacity should remain exposed to the same locational factors as other generation such as loss factors and congestion, and dispatch should not be prioritised from scheme investments.

A3 *Are there financial principles missing, or that have been included but shouldn't be?*

As a general principle, support for new generation should not include the transfer of risk from private investors and shareholders to customers or taxpayers.

We consider there is greater long-term value in jurisdictions deploying funding to research and development of new technologies and grid enablement technologies (i.e., sectors where private capital is unlikely to deployed at scale), rather than to projects where technologies are not already at parity or below incumbent technologies. For those projects, assistance could take the form of auxiliary supports such as planning and development approvals, streamlining and expediting connection processes, and committing to the timely deploying of associated infrastructure. A good example of this support is the type of jurisdictional assistance that is being considered through REZ programs.

A4 *What are some of the market-based signal challenges, if any, with mothballing seasonal shutdown?*

General downwards pressure on wholesale prices from subsidised generation, as well as extended periods of low prices during low-demand periods, will lead to continued changes in the operating profile for all generation assets, including thermal plants. To avoid earlier closures of existing generation, it is critical that options to improve plant operational efficiency are not discouraged or prevented. Mothballing, seasonal shutdowns, two-shifting, or other options that improve the efficient dispatch of the overall generation fleet should be seen as beneficial for the transition and should therefore not be discouraged in any way.

In terms of market signals, steps to mandate the operation of existing generation when it is uneconomic will also restrain the deployment of capital to build new replacement generation that is better suited to recovering costs in the context of emerging wholesale market dynamics.

There are also potentially significant safety concerns with plant that is compelled to run where it has been withdrawn for operational maintenance or other genuine HSE reasons.

A5 *What additional costs or process burden may the disclosure of such information place on stakeholders?*

Continuous disclosure obligations on listed companies, as well as information provisions under existing energy Rules and Procedures (e.g., MTPASA and EAAP) already mandate the disclosure of known information concerning closure dates and detail concerning the operation of existing generators.

While additional information regarding generator operation may elicit speculation about closure date timings, it is unlikely to provide a level of certainty beyond that which is formally provided by the plant operator to the market under existing frameworks.

A6 *What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?*

Information required to understand availability and return to service is already largely published in MTPASA and EAAP or able to be sought by AEMO under existing powers. Where information is not disclosed under these existing frameworks, it is because that information (e.g., regarding forecast plant availability or contract position), is either not known with a sufficient degree of certainty to disclose or is likely to change.

A7 *Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?*

The disclosure of mothballing and seasonal shutdown intentions is already signalled in market disclosures such as MTPASA. Prior to such disclosures of intent, the potential for such shifts in operation will already be apparent to the market through forecast market conditions.

However, the energy market is extremely dynamic, and return to service for a mothballed plant can occur for a number of reasons that are hard to forecast (e.g., replacing other withdrawn capacity, transmission outages, changes in price or demand forecasts, etc.). These dynamic shifts require generators to take account of both long-term trends and short-term market conditions and participate in the market concordantly to maximise potential returns and overall system efficiency.

The greater concern rather than disclosure is therefore risk of a very onerous exemptions process that would seek to compel operators to run their plant when uneconomic or unsafe to do so.

A8 *Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?*

The reason for making mothballing and other plant availability decisions is to operate plant flexibly and efficiently in response to changing market conditions. Applying a long-term notice requirement to mothballing decisions removes this flexibility, and therefore carries a substantial risk of closure dates for plant being brought forward if the risk of being forced to operate uneconomically or unsafely persists. Nevertheless, we understand concerns as described in the Options Paper and consider that a more robust framework for notice of closure does need to be developed; but one that incentivises rather than penalises flexibility.

As a general principle, if mothballing is subject to exemptions process, the process should determine whether or not the decision to mothball carries a risk of serious market consequence, and not just a general decline in system reliability and security as will be likely with the removal of some capacity from the system. For example, the AER or AEMO may seek to consider whether the removal of capacity will cause a breach to the reliability standard that does not already exist.

As a further principle, steps to manage excursions from the reliability standard as a result of mothballed plant should be taken under reserve frameworks. In our view, the development of an operating reserve could consider this type of situation, but also the RERT mechanism may be able to manage system reliability concerns following a mothballing announcement (noting that mothballing is unlikely if there are forecast of tight conditions with commensurate high prices).

In addition to concerns about reliability, system security issues as a result of mothballed plant are unlikely if plant is being adequately compensated for those service through appropriate markets. Rather than an immediate reform, we therefore consider that revisions to the notice of closure exemptions framework should be considered in the context of a market where reserve and essential system services are adequately compensated for, incentivising essential plant to remain in the market where required.

The development of such a framework will require detailed consideration of impacts on existing generation and new investment signals. We have considered this issue in some detail and can provide further information to the ESB in this regard.

A9 *What suggestion do stakeholders have for defining mothballing?*

AEMO and the Reliability Panel have usefully defined the concept in the following way: 'The term "dry stored" is used to identify the status of a generation facility (or plant) that is not in a state of readiness to allow it to be dispatched in the NEM, but remains physically intact, and, after a period of restoration, would be capable of being returned to service. Similar terminology used to refer to this state includes "care and maintenance" or "mothballing"'.[2]

In addition to this definition, there may be some temporal considerations to delineate mothballing from other generator states for the purposes of an exemptions process, such as time to recall or forecast total time unavailable. AGL has explored this further and can providdetailed information to the ESB on request.

A10 *How can governments, market bodies and market participants better work together to be prepared for exits?*

The existing information processes and closure rules already provide a robust platform with which to consider potential closures and consider market impacts, which is evidenced by recent

[2] AEMC Reliability Panel (2019), Template for Generator Compliance Programs, See https://www.aemc.gov.au/sites/default/files/2020-01/template%20for%20generator%20compliance%20programs%202019.pdf

discussions regarding closures of major thermal assets occurring on timeframes that exceed the regulatory minimum (e.g., 7 years for the Liddell and Yallourn plants and 9 years for Eraring).

While there is scope for a much more substantial framework at either a national or sub-national level to consider the broader impacts of asset closures, there is little in addition to be gained by a punitive and mechanistic approach to asset closure rather than collaborative approach to these very substantial issues, which have very broad impacts not just on the energy sector but on regional communities and local economies.

While many of the reforms proposed by the ESB will be helpful to provide some stability to market settings and investment signals for entry and exit of plant, we note that uncertainty about asset closure dates will remain until there is bilateral and multi-jurisdictional support for consistent long term and interim emissions targets and appropriate structures to manage asset closures and provide transitional support to local communities in a more orderly fashion.

A11 *Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?*

Our general position is that governments should not intervene in market, and that even the risk of future intervention to avoid reliability shortfalls can cause a freeze in investment that can be self-fulfilling.

In our view, government resources should largely be directed to solutions that have the lowest overall cost for customers over the course of the transition. It is unlikely, but possible, that it may be an efficient use of funds to sustain a large generator for a short period (in part because of concerns outside of the energy market), but this power should be used exceedingly sparingly and with great caution, considered against the merits of other competing options to achieve the same desired result. That being said, it is a power that should sit with governments and not with market bodies, who have existing market mechanisms available to manage reliability shortfalls through an interventions framework.

A12 *Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?*

If a reliability shortfall should emerge, including as a result of mothballing notification, AEMO should use its intervention powers and conduct RERT contracting. We note in addition to RERT, that our proposal for an operating reserve should alleviate some concerns with the level of available capacity to meet ongoing system demand. If the concern is with a security service, as noted above this should be able to be managed by a UCS mechanism with appropriate mechanisms in place to procure necessary essential system services.

A design option to consider is for a withdrawn generator to participate in RERT tender process following a mothballing notification. For example, if the notice of exemption is denied on the basis of a risk of capacity shortfall, a possible solution could be to look at the types of resources available to provide RERT contracts for a period, and whether a mothballed generator could compete with other resources for RERT requirements. This is potentially a complicated issue that could be considered further in addition to the issues raised in questions A8 and A9 above. AGL has considered this and can provided further information to the ESB on request.

Chapter 2 - RRO questions

A13 *Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?*

We generally support the proposed principles and measures of success as outlined, however, we consider as an addition the ability of the RRO to leverage the broadest range of innovative options to meet the needs of the energy system while minimising costs for customers.

There is also a requirement for any reliability mechanism to provide a level of certainty of its purported impact. For example, the cost of the scheme must translate into quantifiable impacts, such as increases in available capacity, which can be measured to judge the successful of the reform.

This transparency of cost is also critical for retailers, as a key issue for retailer-based obligations is that the cost of any obligation must be able to be passed through to customers, as well as able to be calculated and considered in the setting of regulated retail offers such as the DMO and VDO.

As a principle, the settings of the RRO should align with other market settings (e.g., consistency with the NEM reliability standard) to continue to incentivise investment based on market returns from the spot and contract market, rather than from costs of compliance with the scheme.

Lastly, we note the ESB's concerns that financial markets are backed by insurance and speculation, and not physical generation, but in our view, the impacts of this feature of the NEM are overstated. Most retailers will already be hedged to POE50 demand through generation and use additional risk management products to cover rare events. This is a sensible approach to limit customer costs and maintain reliability to an acceptable standard over the long-term. The current market design does not incentivise a large generator to be built for very rare events (i.e., only to be dispatched for a few hours every decade) and doing so would add substantial cost to the market.

A14 *Are there any obvious priorities given current and plausible likely future market scenarios?*

A key priority is a mechanism that provides certainty to both investors and policy makers that it will achieve its stated objectives of improving the outlook for investment and reducing the risk of capacity shortfall at a cost that is less than competing resource adequacy mechanisms. This certainty of operation, however, will need to operate within a changing market environment and resource mix as the energy transition progresses. This implies both a robust and durable mechanism but one that is structured to deliver outcomes by leveraging the broadest range of available technologies at the lowest cost at any given time.

A15 *What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?*

There is no evidence that the current RRO does not adequately encourage compliance among liable entities. Penalties for not meeting the current RRO framework are already substantial, including non-financial penalties able to be administered under the AER's compliance and enforcement regime, including loss of licence. Accordingly, there is no need to modify the mechanism simply to encourage compliance.

A16 *Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?*

An RRO that encourages the broadest type of contractual arrangements will support flexibility throughout the transition. The ability for the proposed Physical RRO to achieve this (i.e., arrangements with a broad range of demand and supply side options) requires further clarity on the types of generation or demand response incentivised through a physical certificate model, which is not clear at this stage of consultation.

A17 *[Financial RRO option] How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?*

We do not consider that strengthening the RRO signal will significantly derisk investment in new generation over the long-term. In the current NEM, investment in generation to ensure reliability is achieved primarily through NEM price signals and derivative markets.

While a strengthened RRO may provide some additional assurance that higher levels of contracting are in place in the short-term, it remains doubtful that this will translate to the types of large-scale and long-term investments that policymakers are seeking as an outcome from the obligation. Rather, compliance is likely to be met by utilising shorter-term options such as contracting less demand to reduce the compliance burden, contracting additional demand at higher short-term prices, or contracting with expensive short-term supply- and demand-side resources.

This is primarily because the short-term RRO signal is much stronger than the long-term RRO signal, which is not durable enough to derisk major investments.

AGL has provided consistent feedback on the RRO that aligns with this position since consultation on its initial design.

A18 *[Financial RRO option] What are options to make the RRO simpler, while still advancing some measures of success?*

The initial model of the RRO was that it would ideally not be triggered, as participants would have the ability to respond to forecast shortfalls in supply on the basis of the T-3 forecast. An RRO that is not triggered remains the simplest form of the mechanism, consistent with its original design that it should only occur if a prolonged reliability shortfall is observed well in advance and not acted upon.

Additionally, elements of the RRO that appear to have little substantiated value include the book build process and MLO. The process surrounding large customer opt-in, obligations regarding new users, and reaction to a RoLR event, could be removed following further consideration of adverse impacts.

The current process to quantify potential PoLR costs is complex; we suggest that the RRO could be structured more directly as an ex-post allocation of RERT costs, where the AER could assess contract position following periods of RERT intervention and allocate costs to participants that were not adequately hedged during these periods.

A final point is that the UCS and proposed operating reserve may offer more dynamic ways of managing system reliability and intervening in the market – steps to modify the RRO should therefore also consider to what extent RERT or PoLR resources will be deployed in the future and how they may be procured, scheduled, and dispatched, especially in combination with an operating reserve.

A19 *[Financial RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?*

The initial model of the RRO raised concerns that liable participants would have to balance more onerous reliability obligations with the benefit of contracting additional load, especially at periods closer to the forecast reliability gap. There were also concerns regarding to availability of contracts for standalone retailers. As a result, a number of processes were added to the RRO such as the book build, MLO, large-customer opt-in, new retailer, and RoLR processes.

In our experience, however, the existing RRO has not incentivised large loads or smaller retailers to enter into contracts over longer periods of time, as was a stated intention of the obligation.

Modifications to the RRO should recognise that it will remain challenging to incentivise longer-term contracting in advance of forecast high-price periods, and that smaller retailers and large users may indeed seek to remain unhedged to minimise their costs. Rather than being able to mitigate this concern, we consider that this should be identified as an ongoing flaw in the RRO model that affects its ability to deliver additional long-term investment in new generation.

An additional development since the RRO was first implemented is the development of regulated offers across the NEM in the form the DMO and VDO. We note as a general principle that costs from compliance with the RRO, which will be hard to quantify, should be included in the calculation of default offers, and that this may present challenges as costs for different retailers will differ depending on their commercial structure and contracting behaviour.

A20 *[Physical RRO option] Should it be a triggered mechanism, or be developed as a rolling one?*

The physical RRO is similar in form to other international models of capacity markets, which commonly consider the incentives for existing and new generation investment differently. As an example, existing capacity often must bid into annual capacity auctions whereas new capacity is provided an annual payment over a longer fixed period.

Insofar as the Physical RRO is conceptually similar to a capacity market, it would be sensible to align with some of the design features of capacity markets (i.e., with an annual target and a mechanism that is therefore 'always on'). The effect of an 'always on' obligation in years where demand for capacity is low will simply result in a low clearing price.

As a more general point, we note that the Physical RRO represents a very substantial change to existing energy-only market arrangements, and a trigger as well as other fundamental design principles should be discussed through much more substantial consultation within expert working groups if a capacity-type of market model is to be progressed further.

A21 [Physical RRO option] How should the physical certificates be regulated?

It would seem sensible to regulate the entire scheme under the powers of the AER; however, we note that there are matters of scheme design that may justify the creation of an expert panel (similar to the current AEMC Reliability Panel), which could consider elements of the operation of the scheme on a regular basis from a technical and cross-industry standpoint.

A22 [Physical RRO option] How would a physical RRO impact contract market liquidity?

It seems very likely that a Physical RRO could materially weaken contract market liquidity. The Physical RRO requires liable entities to source both energy and reliability certificates from the same provider. It is likely that these products would be regularly stapled under a common OTC arrangement, which would subsequently reduce the availability of exchange-traded derivatives for energy.

As a corollary, there is substantial evidence regarding the bespoke financial arrangements that renewable generators currently enter into regarding both LGC and energy payments.

However, whereas PPAs and OTC contracts with variable renewable generators are encouraged, the challenge with the Physical RRO is that contract market liquidity is perceived as a greater issue with regard to product availability for hedging during high-price periods (e.g., cap products), and it is likely to be these types of products that are stapled to the production of physical reliability certificates.

A23 [Physical RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?

Depending on how the Physical RRO is structured, we consider there is a risk of stifling product and service innovation, peak demand response arrangements, and on-site generation and storage (both small and large-scale), which benefit from limiting exposures to high price periods. This will have an impact on all market customers.

As a general point we also note the issues raised in A22 regarding possible impacts on contract market liquidity.

Lastly, we reiterate the point in A19 that costs from compliance with the Physical RRO, which may be hard to quantify, should be included in the calculation of default offers by regulators. This may present challenges as costs for different retailers will differ depending on their commercial structure and contracting behaviour.

Chapter 3 - Essential System Services, Scheduling and Ahead Mechanisms

A24 What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?

While the development of the UCS should consider the ability to implement an SSM over time (i.e., some degree of futureproofing where possible), and discussions regarding the advantages of a spot market approach for essential services over long-term procurement should continue, we do not consider that an SSM would need to be implemented on the same time frame as the UCS model, which is likely to be pursued at a relatively fast pace.

Prior to the development of an SSM, initial steps need to be taken on which of the other proposed ESS reforms will be implemented, and therefore what additional efficiency will be gained through a SSM market as proposed in the Options Paper.

A25 *What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?*

Arguments concerning the optimal development pathway for resources to efficiently provide long-term delivery of critical synchronous services are complex, and the general principles have been well described in the ESB's Options Paper. In our view, while an SSM may be able to reveal current costs, this price discovery will not necessarily provide adequate information for future system needs, especially as a result of 'lumpy' system impacts such as new transmission build, thermal plant exits, and the commissioning of new synchronous condensers.

A26 *How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?*

We strongly support a dynamic operating reserve as elaborated on in responses of other questions below; however, we consider that an operating reserve is likely to provide more value as a mechanism to maintain system reliability and incentivise dispatchable generation, rather than as a security service.

We do not support the introduction of a ramping service because it is not a technological neutral approach as it creates a market to support certain plant in overcoming a deficiency rather than a market to support providers of a system need. Generation units that require significant ramping have only limited capability in responding to contingency events and should therefore not receive additional incentives on this basis.

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

A27 *What are stakeholder views on the issues raised on supporting market participation for active DER? Are there other paths that could also be considered for different types of consumers?*

Retail/aggregators

We note the proposal that the market framework needs to allow customers to participate in as many of the services as they choose, potentially via different service providers to enable customers to choose offers that suit their needs.

We support continued reform to enable greater contestability in the DER aggregation market, including by subjecting network services to competitive procurement processes.

We see substantial benefits in retailer aggregator model as compared with multiple trading relationships in providing customers with transparency of the co-optimisation of value streams derived from their DER investment as well as more complete consumer protections.

Whilst the independent aggregator model theoretically promises increased competition and innovation on different services, it does not guarantee greater efficiency for the individual customer vis-a-vis orchestration of their assets. Having the multiple trading relationships is highly complex from an operational perspective, may not provide customers with sufficient visibility and risk potential misalignments between the customers' expected value of orchestration and the benefits being realised by the aggregator.

As we highlighted in our formal response to the AEMC's 2019 Issues Paper on Consumer protections in an evolving market,[3] irrespective of the energy service or product provider, customers should be provided with a level of consistency on fundamentals and an

[3] See AGL submission in response to the AEMC Issues paper on consumer protections in an evolving market (11 February 2020), Available at agl_submission_-_aemc_consumer_protections_submission_-_13_feb_public_version_redacted.pdf.

acknowledgement that new energy brings with it not just the service of supply and access, but also a value creation from the customer.

Getting the foundations right to enable the retail/aggregator model should be the priority. Focus should be given to:

- Establishing a fit-for-purpose consumer protections and retail authorisation framework for DER service providers, implementing the recommendations of the AEMC in its 2019 Consumer Protections Review;
- Improving the digital meter framework to allow for cost effective and efficient installation of digital meters; and
- Developing technical standards to promote interoperability across different retailer/aggregator platforms to drive for the best solutions for customers (including installation, communication and inverter manufacturing standards).

Distribution networks

We support the observations that distribution networks' management of the two-way flow of energy requires new ways to manage and monitor systems as well as additional services to keep system within its technical limits (to some extent can be managed through tariff incentives). We also agree that networks need visibility to manage variability and facilitate DER integration.

As a matter of priority, regulatory reform is required to promote the contestable market for non-network solutions. The current framework incentivises distribution owners to seek capital build solutions over non-network solutions as the capital is included in their regulated asset base which boosts their return on capital. We need to ensure that distribution network ring-fencing arrangements are robust enough to avoid causing customer detriment by allowing monopoly owned networks a competitive advantage in delivering cost effective DER integration solutions.

We support the development of competitive-based arrangements where consumers as owners of DER assets cannot only improve the affordability of their energy use through lowering their energy reliance on centrally supplied energy but are also rewarded for offering up their DER assets for wider network and wholesale market-based services. We consider such an approach will deliver the greatest benefit, as DER uptake continues to grow.

We have observed a range of recent regulatory proposals that seek to accelerate the implementation of technical standards and communications protocols for DER, including the SA Government's Smarter Homes Consultation. These responses disempower the owner of the asset to actively participate and support the wider electricity system reliability. Rather, market participant and the operator take control of the customer asset. This outcome increases the payback period of the DER asset investment for the owner and disincentives the uptake of these assets and services by consumers.

AGL also supports investment to improve network visibility of DER but there should be clear regulatory oversight through the AER's Expenditure Forecast Assessment Guideline to ensure efficient expenditure. The assessment framework should weigh the costs associated with networks acquiring metering data from Metering Data Providers against the costs associated with networks establishing effective modelling systems to extrapolate sampled data.

AEMO

We note the commentary that AEMO requires a mechanism to maintain minimum levels of operational demand for power system security. We believe policymakers should consider a range of mechanisms and incentives to facilitate DER supporting power system security.

As far as possible, any interim measures recommended through the maturity plan should draw upon existing market arrangements and provide clear safeguards on the limits of control as well as visibility on the impact to customers.

We note the recent analysis produced by Energy Consumers Australia and CutlerMerz[4] that highlighted the need for solutions to attract social licence to ensure their success, by facilitating net private benefits for DER consumers that exceed costs. We consider that market-based solutions

[4] Energy Consumers Australia and CutlerMerz, Social Licence of Distributed Energy Resources, Final Report December 2020.

have a greater potential to support positive social licence outcomes as compared with the control-based approaches that have been implemented in jurisdictions such as South Australia.

In order to facilitate the emergence of an effective market solution, a sunset clause should be articulated in any emergency backstop mechanism. We consider a three-year time horizon to be appropriate.

The maturity plan should also articulate a clear pathway towards a market-based solution in order to mitigate impact to customers, through the development of appropriate market signals to shape consumer energy use as well as incentives to accelerate investment in supporting technologies, such as batteries and EVs.

A28 Is the unbundling of services delivered by active DER resources (e.g., solar PV, batteries or smart hot water appliances) from energy supplied by DER viewed as important to allow innovation and new business models? What might be the pros and cons of this approach?

AGL supports regulatory reform to better support innovation where it can be demonstrated to deliver greater benefits to consumers. When assessing whether the multiple trader models provide greater benefits to consumers, we consider it important to consider the following guiding principles:

- Whether it empowers consumers to greater choice to participate in a range of competitive market services which address broader energy system needs;
- Whether it facilitates economically efficient access arrangements that appropriately balance the consumer and market benefits with the cost and complexity of implementation; and
- Whether it provides a consistent consumer experience by affording the same rights and protections to consumers regardless of how they choose to receive their energy supply and services.

Accordingly, while we support reform to enable multiple trading relationships, we believe any new arrangements should established clear safeguards to ensure customer enjoy equivalent protections, in order to maximise customers' ability to realise value from their DER asset investment and guard against the risk of consumer harm.

We note several material risks in the flexible trader models, including:

- Added complexity in terms of customer and market settlements and system changes that are likely to impose significant costs on retailers and distributors which may result in increased electricity retail prices for all customers;
- The models do not guarantee greater efficiency for the individual customer vis-a-vis orchestration of their assets. Enabling multiple aggregators at a single customer site risks potential misalignments between the customers' expected value of orchestration and the benefits being realised by the aggregator. In a future where customers have multiple DER assets, they may also benefit from co-optimisation between those assets that would be most efficiently managed collectively rather than by competing aggregation service providers.
- Consumers may experience an inconsistent level of protection in the provision of their aggregation services that could result in customer detriment, unless all aggregators are subject to a consistent consumer protections framework as is applied in the energy retail context.

AGL supports the development of Model 1 that entails an enhanced Small Generator Aggregator (SGA) framework to enable competing aggregators to service different connection points at one site, provided aggregators are required to obtain a retail license and are subjected to equivalent consumer protections. In order to progress Model 1, we would recommend:

- Establishing a fit-for-purpose consumer protections and retail authorisation framework for DER service providers, implementing the recommendations of the AEMC in its 2019 Consumer Protections Review;

- Establish an effective national connections framework to support consistent consumer outcomes in the transition toward dynamic connection agreements. This framework could also contemplate the barriers to customers installing a second connection point in a cost-effective manner.

As we highlighted in our formal response to the AEMC's 2019 Issues Paper on Consumer protections in an evolving market,[5] irrespective of the energy service or product provider, customers should be provided with a level of consistency on fundamentals and an acknowledgement that new energy brings with it not just the service of supply and access, but also a value creation from the customer.

Regardless of the consumer applications in question, be it an EV, battery or hot water system, we consider that electricity should be treated as an essential service and consumers should benefit from equivalent consumer protections to mitigate impact to their retail energy bills. From a customer-centric perspective, the source of energy is immaterial. Customers expect to have the same rights in terms of supply and service. In the new energy context, the expectation may be greater (eg. guarantee of participation/ value creation) but the same basic protections should apply as a matter of equivalence (ie. guiding principles on customer service outcomes). We see material risks in an approach where the AER provides exemptions from retailer authorization for particular use cases, such as the sale of electricity for EV charging.

AGL does not support the development of Model 2, that entails a sub-meter connection point or Private Metering Arrangement (PMA).

We see strong parallels between the flexible trader model 2 presented that utilises a sub-meter connection point and consumers' experience with embedded networks. While the embedded network model in theory presented the potential to deliver benefits to consumers, in practice consumers have not received these benefits due to a lack of equivalent consumer protections and regulatory oversight to ensure appropriate consumer outcomes. These shortcomings informed the AEMC's reform package aimed at provided access to retail market competitive as well as equivalent consumer protections and information disclosure.

We also note that the AEMC considered multiple trading relationships in 2015 and decided not to progress the reform on the basis that it is unlikely to deliver material benefits for most customers but is likely to impose significant costs on retailers and distributors, which may result in increased electricity retail prices for all customers.

We believe that alternatives that draw upon existing market arrangements, including settlement and scheduling by NMI, B2B processes and off-market solutions for non-metering data services may prove more cost effective and less complex whilst maintaining a consistent consumer experience through equivalent consumer protections. It is important to outline what the limitations of the current arrangements are in facilitating increase consumer uptake and effective participation in orchestration services. Without understanding these limitations, seeking to implement a multiple trading arrangement may not be the most cost-effective way to remove any limitations identified.

A29 *What might be implications of a growing fleet of active batteries or electric vehicles? Are other pathways that need to be considered to reflect these needs?*

We consider it important that market bodies develop a fit-for-purpose scheduling arrangement for aggregated assets to best facilitate their interaction with markets as the fleet begins to scale. We would support establishing scheduled 'lite' arrangements that provide equivalent obligations on aggregators as apply to other market participants, though the method of scheduling may differ. In our view, this will enable aggregated assets to interact on a more equal paying field with other large-scale generators, providing benefit to the broader energy market system.

A30 *Are there constraints on switching providers with DERs today? Are constraints on switching likely to occur through standards being introduced now or expected, such as IEEE 2030.5?*

[5] See AGL submission in response to the AEMC Issues paper on consumer protections in an evolving market (11 February 2020), Available at agl_submission_-_aemc_consumer_protections_submission_-_13_feb_public_version_redacted.pdf.

We consider jurisdictional governments' recent focus on implementing product-based technical standards to facilitate the interaction of DER with the broader energy market system risks constraining customers' ability to interact with the market as these standards do not directly accommodate retailer/aggregator use cases and, in some instances, present practical application issues in the Australian energy market structure.

We have seen these risks most readily in the intended application of 2030.5 to support the implementation of dynamic export limits in South Australia as well as the South Australian Government's proposal to accelerate the implementation of the Energy Ministers' 2019 decision to introduce DR capability requirements for air conditioners, EV chargers, pool pump controllers and electric resistive storage water heaters.

We consider that promoting interoperability through technical standards will be a key enabler for the optimisation of distributed energy resources across Australia's energy markets. Nevertheless, we believe substantial work remains to develop Australia's technical standards framework in alignment with international standards that are considered best practice.

We believe governments' focus should be on aligning the regulatory framework with the broader transition of the NEM towards a two-side market through the development of fit-for-purpose and nationally harmonised rules and technical standards to facilitate the growth of DRs and co-optimised DER.

We elaborate our views on sequencing in response to A31 below.

A31 *What are stakeholder views on approaches outlined? What might be the advantages and disadvantages associated with each?*

As a matter of priority, policy efforts should be focused on facilitating scaled market integration of DER through the development of appropriate scheduling arrangements. These reforms should draw upon existing market settlement arrangement by NMI to provide a least cost solution.

In the medium term, the focus should be on better facilitating DER access to provide network services, drawing upon insights from AEMO's Project EDGE.[6] , This will entail consideration of network operational capability to broadcast dynamic communication signals to market as well as the integration of these signals with the AEMO's NEM settlement systems.

To facilitate a mass market response to support system reliability, consideration should also be given to the need for a nationally harmonised technical communications protocol. We note this has been a topic of substantial discussion in the South Australian Office of the Technical Regulator's Dynamic Export Limits Committee. We consider it will be critical that the underpinning technical communications protocol adopted:

- Promotes customer choice and enable customer participation by aligning with internationally accepted standards, where consistent with Australian energy market structures;
- Enables access to secure and open IT platforms as well as technical DER device capabilities; and
- Aligns with the policy direction towards a market-based framework to allow customers to engage and share in DER value.

The API Technical Working Group has made substantial progress in developing an Australian implementation guide for IEEE 2030.5. However, to date this work has focussed solely on network support-based use cases without sufficient attention given to the aggregator/retailer use cases and how they can support consumer uptake of DERs for their home or business. Moving forward it will be critical that the standard applied in Australia supports aggregation use cases at the NMI level to facilitate DER co-optimisation across multiple value streams.

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[6] Project EDGE (Energy Demand and Generation Exchange) seeks to demonstrate an off-market, proof-of-concept Distributed Energy Resource (DER) Marketplace that efficiently operates DER to provide both wholesale and local network services within the constraints of the distribution network. See further AEMO, Project EDGE, Available at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

In the longer-term, as the market for DER services matures, the technical standards framework could also mature to accommodate alternative communications pathways, including to individual devices. However, in this context it will remain important that the framework:

- Supports technical service delivery from devices;
- Aligns with internationally accepted standards; and
- Provides accurate measurement to support financial transactions between multiple parties in the energy supply chain and ensure consumer confidence.

Whilst we acknowledge the work being progressed by the EL-54 Committee with the creation of AS/NZS 4755.2, it is important not to overstate the ability of this standard to support demand response activities in Australia's energy markets. We elaborated on the many practical issues related to the DRED control methodology specified in AS4755 in our 2019 knowledge sharing in the context of our ARENA NSW Demand Response Trial.[7] Moreover, in the context of EV charging, substantial work remains to develop an appropriate standard to facilitate interoperability for consumers between physical and commercial systems.

With the advent of digital meters and more advanced DER that provide new opportunities for customers, AGL believes it is important to establish a fit-for-purpose regulatory framework governing measurement. We note this is being advanced through the Australian Government's Measurement Law Review Consultation. In this context, the regulatory framework should be adapted to:

- Support the accelerating rate-of-change in technological advancements and changing consumer behaviours; and
- Continue to promote consumer confidence by ensuring accurate and robust trade measurement.

A32 Are there other potential approaches that could be considered?

A33 Under what situations could the distribution network operator perform the role of the retailer / aggregator?

We do not consider it appropriate to design towards a market framework that places the distribution network in a de facto market participant. As a monopoly ownership structure, it is difficult to imagine a regulatory framework that incentives network businesses to deliver consumer-based outcomes and reveal information to not allow for clear and transparent benchmarking. The Australian market structure and regulatory framework is based on distribution businesses focussed on delivering a reliable and stable system through 5-year revenue cap determinations.

A34 How might DER assets be managed in a situation where no retailer / aggregator is nominated?

Customers should have sole responsibility on who and how their DER assets are managed. Some consumers may invest in DER solely for the purpose of their own comfort and energy costs. Other consumers will be consider offering up their DER assets for broader system services if they receive what they consider fair, appropriate and transparent reward for offering their DER. In a situation where a consumer has not nominated to participate in the provision of wider system services, AGL would consider an emergency backstop arrangement is appropriate. These arrangements should only be enabled by an independent market operator, such as AEMO, and only after all other competitive solutions have been exhausted.

[7] Available at https://arena.gov.au/assets/2018/09/agl-nsw-demandresponse-report-october-2019.pdf.

A35 What are the issues surrounding connection agreements that can facilitate a retailer / aggregator for market participation and the delegation for the enforcement of limits to both DNSPs and AEMO?

As distribution businesses transition toward dynamic connections, we consider that an independently developed national connections framework is an important foundational requirement. The development of the framework for DER should align with the National Electricity Objective. Empowering an independent authority, such as the AER, to develop national connection guidelines would ensure a balanced approach to maintaining network stability and valuing consumer investments. In consultation with industry stakeholders, the AER should assess network connection applications utilising these technical documents to ensure a harmonised approach.

Second, to ensure consistent consumer outcomes in the delivery of dynamic customer connections will require a greater level of regulatory scrutiny from the AER over distribution networks' expenditure proposals to ensure network investment facilitates the interaction of DER with the broader energy market system.[8] The AER's assessment of dynamic export operating envelopes will also need to be informed by an established customer export value methodology that appropriately values customer impacts and differentiates between historic circumstances of distribution network operation and issues associated with higher DER penetration.

A36 Noting the differences in market arrangements between the WEM and the NEM, are there aspects of the WA DER Roadmap that could usefully inform how certain roles and responsibilities might evolve in the NEM?

While we appreciate the different market structures in the WEM and the NEM, we consider that AEMO's Project Symphony trial that is currently being conducted in WA will provide a range of valuable insights to inform the development of requirements of aggregated DER integration in both markets.

A37 What are stakeholder views on the approaches outlined? What are the potential advantages and disadvantages of each?

We consider there is benefit in exploring further the proposed options to develop structured procurement and the retail portfolio level tariff.

Initial focus should be on structured procurement through the Regulatory Investment Test for Distribution (RIT-D) as this is likely to present the least cost option for industry, although the RIT-D framework presents a number of challenges in effectively attracting competitive market solutions.

We consider that the Australian Energy Council's rule change proposal to give effect to a reduction in the RIT-D cost threshold, below its current $5 million threshold will improve opportunities for non-network solutions.

We also consider that the benefits of contestability should be considered in the context of front-of-the-meter distribution connected energy storage assets to support efficient investment in these assets that could deliver a range of value streams. There is also a need to facilitate sufficiently detailed information to market on distribution network constraints and the power and energy required to defer network augmentation. To facilitate the potential for the competitive market to provide cost competitive non-network solutions at the LV network level, the power and energy required to defer augmentation as well as the annual deferment value that can be paid to an aggregator for services within a geographic area need to be transparent and made available to the market.

Consideration should also be given to the development of a structured procurement digital platform, having regard to the regulatory approach adopted by the UK Government and Ofgem. Competitive-based solutions are at the heart of the UK's approach and since 2017, substantial progress has been made to deliver flexible network services through open market procurement, better and more transparent price signals for flexible action, and provision of transparent network

[8] See further AGL submission in response to the AER on assessing distribution energy integration expenditure (20 January 2020), Available at https://thehub.agl.com.au/articles/2020/01/submission-to-aer-on-assessing-distributed-energy-integration-expenditure.

data has enhanced visibility on opportunities to provide non-network solutions. Relevant examples include:

- Four UK distribution business established a joint 'flexible power portal'12 to broadcast opportunities for flexibility of network services and streamline the procurement process in October 2020. Western Power's contracted flexibility has scaled from 35.3 MW in 2018 to 217 MW in 2020 as a result of this approach.
- UK PowerNetworks publicises its requirements for new network capacity to the market ahead of building network reinforcement and is testing the viability of flexibility network services. By 2023, UK Power Networks estimates its market for flexibility could be over 200 MW.
- SP Energy Networks' FUSION project is also trialling commoditised local demand-side flexibility through a structured and competitive market.
- The retail portfolio level tariff model could also deliver benefits, particularly given the proposed changes being progressed through the recent DER access and pricing rule change to enable pricing to retailers or market small generator aggregators. We would encourage further consideration of the bulk wholesale network tariff model.
- Under this model, distribution networks charge cost reflective network tariffs to retailers based on an aggregated load profile of the retailers' customers. We consider this approach could better incentivise retailers to manage the risks associated with network costs thereby promoting greater innovation in the development of products and service and investment.

Establishing a real time distribution market should represent the eventual evolution of the market once DER scales. Without the scale required to support the cost of establishing such a market, we do not consider it makes sense to prioritise this model at this point in time.

A38 *Are there alternative approaches that could also work to complement existing tariff reform processes that should also be considered? How might these work?*

We consider the proposed changes in the AEMC's recent Draft rule determination[9] to enable pricing to retailers or market small generator aggregators will facilitate greater retail market innovation to support the continued uptake and market participation of DER. By way of example, we would encourage further consideration of the bulk wholesale network tariff model. Under this model, distribution networks charge cost reflective network tariffs to retailers based on an aggregated load profile of the retailers' customers. This approach could better incentivise retailers to manage the risks associated with network costs thereby promoting greater innovation in the development of products and service and investment.

A39 *Do stakeholders have views on additional steps or information that should be considered in the proposed consumer risk assessment tool?*

The iterative risk assessment tool should have frequent check-ins on the costs of additional protections.

The tool only considers if protections are necessary, not whether they are efficient, with the latter left for the rule change process to identify.

Preferable for the tool itself to seek to undertake a summary CBA.

A40 *Do stakeholders have views on the options outlined to address issues associated with falling minimum demand and increasing access to markets?*

We note the commentary that AEMO requires a mechanism to maintain minimum levels of operational demand for power system security. We believe policymakers should consider a range of mechanisms and incentives to facilitate DER supporting power system security.

[9] See AEMC, Access, pricing and incentive arrangements for distributed energy resources, Draft rule determination (25 March 2021).

As far as possible, any interim measures recommended through the maturity plan should draw upon existing market arrangements and provide clear safeguards on the limits of control as well as visibility on the impact to customers.

In order to facilitate the emergence of an effective market solution, a sunset clause should be articulated in any emergency backstop mechanism. We consider a three-year time horizon to be appropriate.

The maturity plan should also articulate a clear pathway towards a market-based solution in order to mitigate impact to customers, through the development of appropriate market signals to shape consumer energy use as well as incentives to accelerate investment in supporting technologies, such as batteries and EVs.

A41 What are other options to consider that might deliver better outcomes for consumers?

A42 Do stakeholders have views on the proposed principles? Are there other principles that should be considered to deliver benefits for consumers?

We would recommend the following principles be considered:

- Customer impact assessment of all new standards;
- Standards should promote customer not system operator control and allow for interoperability;
- Focus on customer outcomes driven by simplicity and transparency;
- Customers should have a choice on whether to offer up DER for wider network services;
- Any interim solutions should use existing frameworks as well as consider future trends taking shape;
- Consumer protections based on two-way flow of energy;
- Pricing and access arrangements that provide for efficient and equity outcomes; and
- Networks should not be provided a competitive advantage based on their ownership structure.

Chapter 5 – Transmission and Access

A43 Does the proposed reform pathway for transmission and access meet the needs of the transition?

AGL agrees that significant transmission infrastructure will be required in the NEM to accommodate the large quantity of new generation investment which will be required over the coming decades. We support the coordinated development of REZs guided by AEMO and the ISP to ensure that local, regional, and wider NEM impacts are appropriately considered. We suggest that REZ rules and guidelines should be consistent across regions as a variety of rules will increase complexity and therefore barriers to entry. We suggest that REZ development rules and guidelines include provisions which ensure that the transmission access available to existing generators is maintained, to ensure that REZ developments do not have detrimental impacts on existing market efficiency.

The ESB is considering whether a broader cost-benefit test for actionable ISP projects is appropriate. While we agree that broader factors such as regional employment and investment are crucial aspects of the transition, they should not be part of the RIT-T. The RIT-T assesses whether proposed transmission investment would be efficient for the consumers who will benefit from that transmission in the provision of their electricity. To include external factors that don't relate to the cost of providing electricity would undermine the test and lead to an inefficient allocation of cost to consumers.

A key deficiency of the proposed reform pathway for transmission is the presumption that open access has failed in the NEM and that an access regime is necessary. While new connecting generators in the NEM over the last decade have often faced network constraints, improved access to system information due to the Transparency of new projects rule change, combined with the Integrated System Plan and Renewable Energy Zones are likely to significantly improve this problem and therefore it is not clear that the proposed introduction of LMP and FTRs are necessary given their complexity and the disruption their implementation would create.

Transmission access schemes can also increase barriers to entry by favouring one investor over another. The advantage may be increased knowledge in how to best participate in the process which allocates the rights (e.g., access to better data which allows better assessment of the value of the rights), an advantage in procuring the access rights due to better timing (e.g., an existing player will be more cognisant of allocation deadlines), or an advantage due to market share or portfolio effects.

Further, transmission access schemes can also undermine the efficient allocation of generation investment due to their inflexibility. With open access, generators are not constrained by the availability of access rights in decisions regarding their connection capacity and timing, while a transmission access scheme will necessarily have limitations.

As generation and transmission assets commence, cease, or modify their operation this will impact efficient allocation of generation investment in an area. Under open access, the market will respond to the market forces driven by these changes, while if an access scheme applies a market response will only be possible to the extent that the availability of access rights can be modified in a timely manner.

A44 For each medium-term access option presented in Part B: Do you think that the model satisfactorily addresses the access reform objectives set out above? If any, what is your main criticism of the model? What additional detail do you require to understand the option?

AGL does not support the introduction of any of the proposed interim access options, especially given the design of the suggested long-term access model has not been resolved. We do not consider that a thorough cost, benefit, and detriment analysis has been made to justify the introduction of an access regime in the NEM. We suggest that the introduction of a potential access regime in the NEM should be considered after the NEM 2025 reforms have been implemented, when the market design is no longer in flux, since a transmission access regime is not necessary for the ESB to meet its objectives.

Our main criticism of the congestion management model (CMM) is that it is targeted at reducing incentives for disorderly bidding, and the incidence and impact of disorderly bidding in the NEM has not been shown to be of great significance. While generators may often bid to floor, this will typically be due to start-up (or ramping) requirements, portfolio effects, imperfect information, or other legitimate reasons not appropriately characterised as disorderly bidding.

The modified congestion management model which allocates rebates to REZ tender participants only would have the same shortcomings as the CMM. We note that access regimes in REZs that have investment safeguards (for example the NSW Roadmap Long Term Energy Service Agreements) may be of limited utility since the revenue certainty offered by the safeguards may mean that generators need not separately consider the risk of congestion. In addition, access regimes will also have reduced utility where a REZ administrator has a central planning role in defining the technology mix for a REZ.

The locational connection fee model imposes increased complexity, uncertainty, and costs on new connecting generators which will increase barriers to entry. It uses an administrator, rather than market forces, to determine the marginal cost of congestion or cost of required transmission infrastructure upon which the connection charge is based. We expect that an accurate determination of the efficient connection charge will be difficult. The imposition of this fee represents a barrier to entry since it is a sunk cost not imposed on existing participants. As a result, this model would reduce market efficiency by undermining signals for plant to exit, enter, or remain in the market.

The generator transmission use of system (GTUOS) charge model exposes generators to an ongoing charge based on the cost of transmission in their area. We agree with the ESB's assessment that given these charges will vary periodically it will be difficult for generators to mitigate the risk of unpredictable changes in these costs. To apply GTUOS to existing generators would not be equitable since existing generators cannot respond to locational signals and the state of the network in their area is largely out of their control since upgrades are determined by a central planner and local entry and exits may have fundamentally changed the character of the network. Whereas to apply the charge to new entrants only would raise barriers to entry and disrupt efficient market signals for exit, entry, and remaining in the market.

A45 *Which medium term access option is preferable?*

As explained in A43 and A44 AGL does not support the introduction of a medium-term access option.

A46 *Are there alternative options that the ESB should consider?*

We suggest that the ESB retain the existing open access regime at least in the medium term.

A47 *Are there potential improvements to the options that the ESB should consider?*

No. The introduction of an interim access model would not be appropriate.

A48 *Would enhanced congestion information help to improve the coordination of* transmission *and generation investment? If so, what additional information would add value?*

Enhanced congestion information would help to improve the coordination of transmission and generation investment. Increased transparency and access to AEMO's system modelling would be beneficial.

A49 *What are stakeholder views on when these arrangements should be implemented* by*? What should be taken into account when determining implementation timeframes?*

We suggest that the introduction of a potential access regime in the NEM should be considered after the NEM 2025 reforms have been implemented, when the market design is no longer in flux.

Part B

Resource Adequacy Mechanisms

No further consultation questions in Part B

Essential System Services, Scheduling and Ahead Mechanisms

B1 *What are stakeholder views on the interactions between the proposed investment and operational procurement mechanisms for structured procurement?*

In what other circumstances to the ones listed in the paper would having both mechanisms be complementary to one another? How should they be designed to support this complementarity?

In what circumstances might having both a long-term and short-term procurement mechanism potentially cause unintended consequences? What should be done in the design to mitigate these risks?

What are the potential impacts, in either or both mechanisms, for the different segments of industry, for efficient investment in transmission and generation, and efficient operation of the system?

AGL's position on these issues and the procurement of system strength generally are considered in further detail in our submission to the AEMC's 2020 Investigation of system strength frameworks in the NEM[10] and in our submissions to the ESB's 2020 Directions Paper.[11]

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. We note that this factor may also undermine the effectiveness of an inertia market, since the commitment of synchronous units for the provision of system strength and inertia cannot be easily 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.

In energy and frequency markets, quantities are determined on the basis of forecasts, but the combination of generation units which can meet those needs is determined by a central dispatch engine. This contrasts with system strength and inertia, 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.

For the above reasons, AGL considers the nature of system strength and inertia may make them unsuitable for provision through a decentralised market which relies on the forces of demand and supply to determine prices. We consider a centrally co-ordinated model for the provision of system strength and inertia services in the NEM with a competitive tender process for remediation, and an appropriate mechanism for scheduling and dispatch, may be the most efficient mechanism for the provision of system strength and inertia in the NEM given the local blocky nature of demand for these services.

We also note that some theoretical approaches (e.g., rapid iterations for co-optimised markets) may be limited by the capability of the central dispatch engine to perform necessary calculations in a timely manner (e.g., the Options Paper notes that a UCS solution may take up to 90 minutes to identify).

B2 *How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?*

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

[10] See, AGL submission to AEMC's 2020 Investigation of system strength frameworks in the NEM, available at: https://thehub.agl.com.au/-/media/thehub/documents-and-submissions/2020/agl-response-to-aemc-system-strength-discussion-paper-14-may.pdf?la=en&hash=E8DFAB9400483B090072B15E6F73F199

[11] See, AGL Submission to ESB Psot-2025 Directions Paper, available at: https://thehub.agl.com.au/-/media/thehub/documents-and-submissions/2020/post-2025-market-design-submission.pdf?la=en&hash=E2771C722869C470D0E36C914EB36DF1

therefore it would define the system strength shortfall without mandating the technology required to remedy it.

B3	*Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids. If so, why? If not, why not?* The design of the UCS should be pursued with the principle in mind of continuing to minimise the duration and frequency of market interventions. Regular reliance on interventions carries the risk of revenues being subject to centrally committed decisions, which carries a risk of market distortions over time. As much as possible, resources should therefore remain incentivised to self-commit in energy and service markets, which should be operated with a clear cost minimisation objective. Further operational tools such as the UCS and settings to intervene should only occur when absolutely necessary to keep the system secure.
B4	*Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern? If so, are the proposals put forward by the ESB sufficient to address this concern? If not, what should be done to mitigate this concern?* As per the answer to the above question, the UCS and settings to intervene should only occur when absolutely necessary to keep the system in a secure state.
B5	*If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?* Over time, the intention of mechanisms and market reforms should be to limit interventions to avoid impacts on spot market pricing, which can be material. System operator interventions and settings that impact on the spot market have been a feature of the market since its inception, and various accounts have been made to assess the loss of dispatch efficiency that can be attributed to them. At the same time, detailed consultation has recently occurred with the AEMC regarding issues relating to intervention prices and impacts on participant revenues as a result of interventions that are occurring more frequently. AGL has provided a substantial amount of feedback to the AEMC in particular regarding the specific operation of intervention pricing frameworks and other methodologies to determine participant compensation. As a general principle, if the unit commitment for security occurs only to the extent necessary to keep the system in a secure state, these distortions will remain an acceptable feature of the market, as long as compensation for affected participants is fair and reasonable. The calculation of ‘fair and reasonable’ compensation, however, and broader impacts on the spot price during market interventions, are issues which should be considered more closely in parallel with the development of service markets and the UCS framework generally.
B6	*What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?* Anticipated UCS commitment decisions should be reflected in predispatch, which would reflect the current good faith bidding obligations which generators are subject to.
B7	*Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.* Predispatch is an iterative process, reflecting the extremely dynamic nature of the NEM and changing market conditions over time. These iterations are a key feature of the dispatch process and should not be discouraged as they result in efficient dispatch.

The concerns raised in this question can already be considered with regard to the existing predispatch and interventions process. For example, surety that availability and bids reflect genuine participant intentions are formalized through good faith bidding obligations, and a strong compliance and enforcement framework to ensure that obligations are adhered to.

B8 *What are stakeholders' views on the best way to address the potential decommitment?*

As above. We note that the existing compliance and enforcement framework, as well as opportunities for the regulator to investigate and take action on breaches of obligations are already very substantial.

B9 *How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?*

There appear to be potential technical limitations to an optimal UCS design; for example, the fact that a UCS solution may take around 30-90 minutes to resolve.

These limitations may impact on the ability to design optimal timings for interventions. Further work needs to be undertaken with AEMO to understand the limitations of the model to iterate alongside predispatch and understand the impact of any temporal limitations on an optimal market model.

B10 *Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?*

Yes.

B11 *How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?*

AEMO should be able to provide the parameters for system services in a transparent way, without those parameters necessarily mandating the types of technologies that can meet the requirement. It is clear, however, that due to the blocky and localised nature of certain services, some needs are only likely to be met be very specific resources in the immediate term.

B12 *Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer? If so, why? If not, why not?*

The preference would be for all requirements to be scheduled through the UCS; however, a substantial amount of work needs to be undertaken to understand all combinations of system service needs that are able to be scheduled, and whether there is a need for additional interventions, at least in the short-term, as the UCS mechanism develops and evolves and following a more detailed understanding of any technical limitations with UCS operation.

B13 *Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?*

Yes. Improved predictability of potential interventions, leading to more accurate forecasts for investment in energy infrastructure is one of the major potential advantages when compared to AEMO's existing manual intervention process.

B14 *How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?*

High ramping and periods of uncertainty can be efficiently managed through self-commitment and the predispatch process without a specific ramping mechanism. Indeed, the iterative predispatch process ensures that dispatch efficiency is maximised during particularly dynamic periods.

B15 *What challenges are envisaged in a future with higher variability and uncertainty in net demand?*

Higher variability in demand necessitates flexible options for meeting policy objectives; for example, a resource adequacy mechanism that is dynamic and responsive to changes in the market on a 5-minute timeframe (such as AGL's operating reserve described below), rather than mechanisms that seek to establish compliance obligations based on long-term forecasts.

As a more general point, the ability of the NEM to adapt to increased variability will be limited because the market price cap (MPC) and cumulative price threshold (CPT) interventions reduce revenue and investment signals for different generation types in different proportions, but to fast-response, firm, and flexible generation in particular. The ESB has not expressed any desire to consider this issue in more detail as a part of the Options Paper.

B16 *How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?*

AGL's proposal for a dynamic operating reserve (DOR) is slightly different to the operating reserve as considered by the AEMC, which focused on reserves to act as a security service rather than a reserve that could act as a useful resource adequacy mechanism. We propose a DOR that acts as an additional market, co-optimised with energy and FCAS. It may be helpful to think about it in terms of a 30-minute raise FCAS service, with a relatively high quantity of MW being procured (e.g., many hundreds of MW within a region).

The amount of reserve to be procured could be set by AEMO or Governments. It could equal the largest or two largest generating units (i.e., N-1 or N-2), the forecast uncertainty measure (AEMO's FUM), or be set by any other type of calculation (e.g., 20% headroom). The main design feature to note is that it would be dynamic: that is, the amount of reserve would depend on system conditions at the time, calculated at 5-minute intervals, and potentially aligning with identified system needs under AEMO's UCS model. This means it would respond to changing market conditions.

The price of the reserve would also be dynamic, like FCAS markets, co-optimised with energy on a 5-minute basis. At most times, we would expect that the cost of the operating reserve would be very low (e.g., near zero or a few $/MWh), as there would be substantial headroom available in the generation fleet to easily participate in a reserve. It is likely that low availability-cost generation like hydro, as well as any headroom on thermal generation, could sit in the reserve at low cost. Generation that is sitting in the reserve would receive a payment for the cleared reserve price, regardless of if it were dispatched. If it was dispatched, it would receive the energy price. For most periods of the year, we therefore expect that the DOR would have negligible impact on prices.

During periods of tighter market conditions, however, when the supply demand balance tightens the price of the reserve would be higher. At periods of very tight supply (LOR1 and LOR2), the cost of the reserve may be very high (i.e., commensurate with energy prices around these periods). This price volatility would lend itself to hedging arrangements, and indeed we would expect that generators could include DOR prices in existing cap products that they offer to retailers to hedge against high reserve prices, which would in turn provide additional revenue to dispatchable generation and insurance against high reserve prices. In effect, it would be a way to incentivise an increase in the cap price without needing to increase the current MPC, which would have a twofold impact:

- providing certainty of a reasonable amount of available generation at all times beyond that which is committed in the energy-only market; and
- providing additional revenue to dispatchable supply (as well as demand side options), which may improve the case for investment in flexible generation and for the development of more robust demand side options (i.e., as a 'scheduled-lite' participant as proposed elsewhere in the Options Paper)

There are however a number of discrete design options that could be considered further to optimise the operation of the DOR with other elements of the Post-2025 reform package.

AGL has modelled a DOR market with a high level of granularity: while impacts depend on design choices, we note that reliability can be maintained to 0.0006% USE with a modest increase in prices. We have provided further information regarding this model to the ESB but would be very keen to discuss the option in further detail with the ESB and market bodies to refine an optimal and preferred design.

B17 *Who should pay for reserves and why?*

Costs of a dynamic operating reserve market should be recovered from market customers, which would incentivise contract cover from generators providing that service.

This is consistent with the operation of high energy prices at periods of high demand, and principles that underpin the operation of the RRO.

B18 *How would the fleet described in the case study have positioned itself under current frameworks in a future with higher net demand uncertainty? Would it have provided more ramping reserve?*

See answer to B14.

B19 *In what circumstances would a reserve service be beneficial for consumers?*

In our modelling, a reserve would be a less expensive resource adequacy mechanism than other models proposed, resulting in overall lower prices for customers. We also consider that the DOR would provide a more accurate price signal for new investment, and a genuine way of reducing the need for interventions in the market, thereby providing additional value due to reduced investment risk and improved signals for investment.

As modelled by the AEMC, the DOR would not manage all possible high-impact low-probability events; however, we note that the cost of building the system to manage many of these extremely rare events is likely to be prohibitively expensive to consumers.

Integration of Distributed Energy Resources and Demand Side Participation

B20 *What are stakeholder views on the proposed maturity plan approach and priorities identified for the first release?*

AGL supports the focus of the first release of the maturity plan on minimum demand. To manage the emerging system security challenge of minimum demand, interim emergency backstop arrangements may need to be established that can be superseded with market-based solutions as investment in smart inverters and energy storage solutions scales. As far as possible, any interim measures recommended through the maturity plan should draw upon existing market arrangements and provide clear safeguards on the limits of control as well as visibility on the impact to customers. The maturity plan should also articulate a clear pathway towards a market-based solution to mitigate impact to customers, through the development of appropriate market signals to shape consumer energy use as well as incentives to accelerate investment in supporting technologies.

AGL also generally supports the proposed topics for future releases of the maturity plan.

The maturity plan should also provide clear direction and timeframes for the development of the following supporting measures for the development of a more mature market for DER services:

- Fit-for-purpose consumer protections framework for DER service providers, implementing the recommendations of the AEMC in its 2019 Consumer Protections Review;
- Effective network economic regulation to ensure networks compete in the contestable market on an equal footing to prevent cross-subsidisation and potential consumer harm, including through strengthened ring-fencing arrangements to prevent direct investment in battery storage;

- Clear parameters on investment in ‘community’ distribution level storage to ensure monopoly network businesses do not displace the competitive market for DER services, that is better placed to facilitate co-optimisation between multiple value streams that adhere to energy storage;
- Network access and pricing arrangements to support efficient planning and investment for export services whilst also addressing equity concerns in non-DER customers’ cross-subsidisation of DER customers’ use of the distribution network.
- Appropriate governance arrangements for DER Technical Standards through the forthcoming DER Technical Standards Governance Review, including mandatory consumer cost benefit analysis;
- Improved deployment of advanced metering arrangements to enable the market to scale, following the AEMC competitive metering arrangements review;
- Establish an effective national connections framework to support consistent consumer outcomes in the transition toward dynamic connection agreements; and
- A national program to develop interoperability standards to support market integration and customer choice.

In addition to the subject matter content of the maturity plan program, consideration should be given to relevant market bodies and Commonwealth agencies to progress reform programs, including the AEMC, AEMO, AER and ARENA. This will ensure consistent approaches are adopted across the NEM and is important to support future releases of the maturity plan.

B21 *Do stakeholders have any feedback on the approach for developing the trader-services model pathway?*

As noted above, AGL supports regulatory reform to better support innovation where it can be demonstrated to deliver greater benefits to consumers. When assessing whether the multiple trader models provide greater benefits to consumers, we consider it important to consider the following guiding principles:

- Whether it empowers consumers to greater choice to participate in a range of competitive market services which address broader energy system needs;
- Whether it facilitates economically efficient access arrangements that appropriately balance the consumer and market benefits with the cost and complexity of implementation; and
- Whether it provides a consistent consumer experience by affording the same rights and protections to consumers regardless of how they choose to receive their energy supply and services.

Accordingly, while we support reform to enable multiple trading relationships, we believe any new arrangements should established clear safeguards to ensure customer enjoy equivalent protections, in order to maximise customers’ ability to realise value from their DER asset investment and guard against the risk of consumer harm.

While the independent aggregator model theoretically promises increased competition and innovation on different services, it does not guarantee greater efficiency for the individual customer vis-a-vis orchestration and co-optimisation between their assets. Having the multiple trading relationships is highly complex from an operational perspective, may not provide customers with sufficient visibility and risk potential misalignments between the customers’ expected value of orchestration and the benefits being realised by the aggregator. This risk increases where the SGA/ PMA is empowered to orchestrate independent to the customers’ retailer. While the SGA/PMA may be motivated to sell excess consumption to the grid during a high-price interval, this could impact a customer's own ability to self-optimise generation to reduce cost. It could also impact retailers’ ability to predict customers’ consumption patterns and their ability to manage cost through hedging.

AGL supports the development of Model 1 that entails an enhanced Small Generator Aggregator (SGA) framework to enable competing aggregators to service different connection points at one site, provided aggregators are required to obtain a retail license and are subjected to equivalent consumer protections.

As we highlighted in our formal response to the AEMC's 2019 Issues Paper on Consumer protections in an evolving market,[12] irrespective of the energy service or product provider, customers should be provided with a level of consistency on fundamentals and an acknowledgement that new energy brings with it not just the service of supply and access, but also a value creation from the customer.

Regardless of the consumer applications in question, be it an EV, battery or hot water system, we consider that electricity should be treated as an essential service and consumers should benefit from equivalent consumer protections to mitigate impact to their retail energy bills. From a customer-centric perspective, the source of energy is immaterial. Customers expect to have the same rights in terms of supply and service. In the new energy context, the expectation may be greater (eg. guarantee of participation/ value creation) but the same basic protections should apply as a matter of equivalence (ie. guiding principles on customer service outcomes). We see material risks in an approach where the AER provides exemptions from retailer authorisation for particular use cases, such as the sale of electricity for EV charging.

In order to progress Model 1, we would therefore recommend:

- Establishing a fit-for-purpose consumer protections and retail authorisation framework for DER service providers, implementing the recommendations of the AEMC in its 2019 Consumer Protections Review;
- Establish an effective national connections framework to support consistent consumer outcomes in the transition toward dynamic connection agreements. This framework could also contemplate the barriers to customers installing a second connection point in a cost-effective manner.

AGL does not support the development of Model 2, that entails a sub-meter connection point or Private Metering Arrangement (PMA)

As we elaborated above, there are strong parallels between the flexible trader model 2 presented that utilises a sub-meter connection point and consumers' experience with embedded networks. While the embedded network model in theory presented the potential to deliver benefits to consumers, in practice consumers have not received these benefits due to a lack of equivalent consumer protections and regulatory oversight to ensure appropriate consumer outcomes. These shortcomings informed the AEMC's reform package aimed at provided access to retail market competitive as well as equivalent consumer protections and information disclosure.

We also note that the AEMC considered multiple trading relationships in 2015 and decided not to progress the reform on the basis that it is unlikely to deliver material benefits for most customers but is likely to impose significant costs on retailers and distributors, which may result in increased electricity retail prices for all customers.

B22 *What technical and regulatory barriers, challenges and opportunities may Model 2 present to Traders, end-users and distributors? What challenges would be present for metering services in either model?*

We consider that model 2 presents substantial cost and complexity and is unlikely to deliver efficiency gains for DER customers.

We believe that alternatives that draw upon existing market arrangements, including settlement and scheduling by NMI, B2B processes and off-market solutions for non-metering data services may prove more cost effective and less complex whilst maintaining a consistent consumer experience through equivalent consumer protections. It is important to outline what the limitations of the current arrangements are in facilitating increase consumer uptake and effective

[12] See AGL submission in response to the AEMC Issues paper on consumer protections in an evolving market (11 February 2020), Available at agl_submission_-_aemc_consumer_protections_submission_-_13_feb_public_version_redacted.pdf.

participation in orchestration services. Without understanding these limitations, seeking to implement a multiple trading arrangement may not be the most cost-effective way to remove any limitations identified.

B23 *How might the designs be improved to accommodate and facilitate greater trading of non-energy services from either model?*

B24 *What are the benefits and risks of enabling arbitrage between separate connection points? If there are risks, including for retailer and network tariffs, how should they be mitigated?*

As noted above, while the independent aggregator model theoretically promises increased competition and innovation on different services, it does not guarantee greater efficiency for the individual customer vis-a-vis orchestration and co-optimisation between their assets. Having the multiple trading relationships is highly complex from an operational perspective, may not provide customers with sufficient visibility and risk potential misalignments between the customers' expected value of orchestration and the benefits being realised by the aggregator. This risk increases where the SGA/ PMA is empowered to orchestrate independent to the customers' retailer. While the SGA/PMA may be motivated to sell excess consumption to the grid during a high-price interval, this could impact a customer's own ability to self-optimise generation to reduce cost. It could also impact retailers' ability to predict customers' consumption patterns and their ability to manage cost through hedging.

Accordingly, while we support the development of Model 1 that entails an enhanced Small Generator Aggregator (SGA) framework to enable competing aggregators to service different connection points at one site, all aggregators should be required to obtain a retail license and are subjected to equivalent consumer protections.

B25 *Do stakeholders consider there to be high implementation costs for any of these options? If so, would these costs be borne by all system users or predominantly by the party choosing to enter the flexible arrangement?*

We consider that both options will entail implementation costs that may not be justified, given there is limited evidence that they will deliver any overall efficiency gain for DER customers. Option 1 will impact retailers' ability to predict customers' behavior and associated hedging strategies, resulting in a higher cost to serve. Option 2 would have higher system wide costs to be borne by all system users, including consumer connections, wiring arrangements and market settlement systems.

B26 *Are there other options the ESB could consider on the path to support more flexible trading for end-users?*

We believe that alternatives that draw upon existing market arrangements, including settlement and scheduling by NMI, B2B processes and off-market solutions for non-metering data services may prove more cost effective and less complex whilst maintaining a consistent consumer experience through equivalent consumer protections.

Consideration should also be given to innovative network tariff arrangements to support greater efficiency in retail aggregation services.

B27 *Are the stated objectives appropriate? Should additional objectives be considered in the design of a 'scheduled lite' arrangement?*

We support the objectives for scheduled lite articulated, namely:

- Creating a framework to encourage greater participation of responsive resources;
- Improve the efficiency of dispatch outcomes; and
- Improve the efficiency of forecasting and scheduling outcomes.

B28 Are there any additional or alternate principles that should be considered?

B29 Are there any additional scheduled lite models or design elements that should be considered through this process? If so, what are the purpose, key features and benefits?

B30 Are the forecasting requirements proposed for the visibility model appropriate? Are there alternate options for granularity, frequency and use?

We support the forecasting requirements proposed for the visibility model. Nevertheless, as the market continues to develop, we would recommend IT build requirements be contained to limit costs that could otherwise scale disproportionately to the benefits gained by participating customers.

We consider this model would be most beneficial within a mandatory framework, that provides some form of standard penalty arrangement. Nevertheless, the framework should provide clarity on the point at which there is a need for accuracy, accounting for the maturity of the market, and the practicality and cost of compliance.

B31 Are the bid requirements appropriate for the dispatchability model?

While in principle we support reform towards scheduled lite arrangements, we consider that further discussion is required on the precise detail of these arrangements to ensure they are cost effective and can be scaled over time to support a maturing market.

We consider that the dispatchability model may be too onerous now, as compared with the visibility model. We note that the matter of interoperability and appropriate communications standards remains unresolved. Moreover, there is a risk of disproportionate IT costs being imposed across a fleet of different vendors without a corresponding benefit in terms of market scale.

B32 What are the barriers, if any, to self-forecasting? How far ahead of time would a resource be able to provide meaningful forecasts of their likely behaviour?

Distribution networks' ability to provide forecasts to aggregators on operating limits applicable to a particular customer site can prove a barrier to aggregators' ability to self-forecast.

Whilst self-forecasting requires a level of sophistication on the part of the aggregator in terms of supporting operating systems, we consider this an important input into the operation of the energy market system and therefore a reasonable barrier to market participation.

B33 How appropriate is the use of threshold accuracy and non-financial penalties for inaccuracy? What are the trade-offs of using this approach?

We support the application of the threshold accuracy approach (for example an 80 per cent accuracy approach) given that these resources are unlikely to impact the operational security of the market. We consider this approach strikes the right balance between providing a degree of operational certainty and mitigating the practicality and cost of compliance.

B34 How appropriate is the proposed approach for the dispatchability model? Will the use of the threshold meaningfully reduce barriers to participation? What are the trade-offs associated with the use of a threshold? How should that threshold be determined (e.g., MW accuracy, or proportion of dispatch targets etc.)?

As noted above, we consider that the dispatchability model may be too onerous now, as compared with the visibility model. We note that the matter of interoperability and appropriate communications standards remains unresolved. Moreover, there is a risk of disproportionate IT costs being imposed across a fleet of different vendors without a corresponding benefit in terms of market scale.

As in the case of the visibility model, we support the application of the threshold accuracy approach as the market for DER services continues to scale.

B35	*Should an opt-out approach prior to dispatch, like that used in New Zealand, be adopted? Would that meaningfully reduce any barriers to participation?* We consider there are inherent risks in an opt-out provision, as this option may be used by participants to avoid scheduling at a time when it is most useful to support the optimisation of the energy market system. In circumstances where participants have developed an ability to bid and respond to scheduling, we do not foresee any individual savings to be realised in temporarily switching off the scheduling.
B36	*How appropriate are the proposed additional participation elements for the visibility and dispatch models?*
B37	*For the dispatchability model, will the use of lighter SCADA arrangements meaningfully reduce barriers to participation? What other types of solutions could be considered?*
B38	*Aside from those listed above, should the ESB consider any other elements of the scheduling framework when designing additional participation requirements for scheduled lite arrangements?* We would recommend that the scheduled lite arrangements be implemented through a mandatory framework, to support a standard penalty arrangement.
B39	*How appropriate are the proposed incentives for the visibility model, including: avoided FCAS costs, reduced operating reserve costs (if introduced)? Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?* We are not convinced that the incentives would support voluntary adoption of the schedule lite arrangements, given that these exemptions already apply to generators who become scheduled. Accordingly, we would recommend that the scheduled lite arrangements be considered through a mandatory framework to ensure consistent application across the market.
B40	*How appropriate are the proposed incentives for the dispatchability model, including: avoided FCAS costs, reduced civil penalties, avoided RERT costs, avoided RRO costs and the ability to underwrite qualifying contracts (subject to firmness rating), reduced operating reserve costs and ability to bid into operating reserve market (if introduced)?* We have similar reservations with respect to the proposed incentives for the dispatchability model, that are unlikely to support voluntary adoption of the scheduled lite arrangements. We consider a mandatory approach may be necessary.
B41	*Are these incentives material enough to incentivise participation under this model? What other incentives should be considered for this model?* Refer B39 above.
B42	*Are there benefits of making a distinction between active (or controllable) and passive (not controllable) behaviours behind a connection point?* No, bidding for non-controllable elements at a particular connection point would be trivial and could simply be added to the controllable bid. Our preferred approach is that all parties treat the entire connection point as controllable.

B43 How might a market participant (retailer; aggregator) provide information across their portfolio (many connection points)?

We consider that aggregators should bid to the granularity of the Transmission Node Identifier (TNI) rather than regionally. Given that the dispatch engine operates nodally, it will require locational information.

Transmission and Access

No further consultation questions in Part B