



19 October 2020

Dr Kerry Schott AO
Independent Chair
Energy Security Board

Submitted by email: info@esb.org.au

Dear Dr Schott

Post-2025 Market Design Consultation Paper

Origin Energy Limited (Origin) welcomes the opportunity to provide comments on the Energy Security Board's (ESB) Post-2025 Market Design Consultation Paper.

The National Electricity Market (NEM) is at an important cross-roads, with the development of the right policy settings crucial in ensuring a smooth transition and resilience over time. Origin considers the ESB has made good progress in determining a suitable future market framework, though we are cognisant much of the detail (that will have a bearing on the efficacy of the proposed options) will need to be worked through.

There are two critical factors in ensuring resource adequacy in the NEM – the viability of current generators; and incentivising new investment (particularly in dispatchable generation and demand side resources), needed to replace retiring plant and supplement the increasing entry of variable renewables. The plan to value essential services and introduce an operating reserve would provide an additional revenue stream and ensure generators (and all relevant resources) are compensated for helping to stabilise the system.

Origin is less optimistic, however, the proposals to strengthen investment signals are appropriate. The Retailer Reliability Obligation (RRO) and other more extreme decentralised mechanisms are too indirect and logistically cumbersome and will not guarantee the delivery of capacity to meet the needs of the system, or government expectations. The operating reserve, while useful in sharpening short term signals, is unlikely to do so for long term investments. It would not provide enough certainty around the timing and magnitude of future revenue given the increasingly variable nature of prices in the transitioning energy only market. Prospective new entrants need to de-risk at least a portion of their investment for a bankable period which is not aided by the RRO or operating reserve.

Origin therefore suggests the ESB adopt a first principles outcomes-based approach by expanding its consideration of options to include a targeted mechanism for new dispatchable resources. Such an approach could provide competitively determined capacity contracts for a suitable period, and better ensure the delivery of new investment. Importantly, it would also provide a consistent framework that could be applied across the NEM to meet jurisdictional reliability targets, negating the need for government interventions that continue to dampen investment sentiment.

The work in developing the Unit Commitment for Security (UCS) should be prioritised to the extent it will help to streamline and enhance the current process around market directions. There is no reason to continue with the design of an ahead market for system security or energy at this point.

To overcome any inherent supply-side bias, Origin supports greater incorporation of the demand side and steps toward a two-sided market where progress is likely to be gradual and dictated by the pace of technological change and the willingness to participate. The ESB should provide greater clarity around the scope, rationale, and intended objectives of this market design initiative (MDI). Similarly, the work on distributed energy resources (DER) would benefit from greater direction, and where appropriate should be merged with relevant sections of the two-sided market MDI.

The current mismatch between the timing of generation and transmission investment has highlighted the need for better coordination between the two. Where generators connect prior to the undertaking of the necessary transmission augmentations it results in network curtailments and queuing that is currently being experienced in some regions. Resolving these issues should be prioritised through development of the Renewable Energy Zone (REZ) concept and continued evolution of AEMO's Integrated System Plan (ISP). We note the Australian Energy Market Commission (AEMC) is well advanced in developing changes to the access regime, with a proposal to introduce locational pricing. However, it is impractical to consider or implement changes to access without first tackling the obstacles impeding better coordination. At that time, Origin also suggests that a broader suite of options be considered (if changes to access are deemed necessary), given the added risks the AEMC's model will introduce.

If you wish to discuss any aspect of this submission further, please contact Steve Reid at steve.reid@originenergy.com.au or on 02 9503 5111.

Yours Sincerely,

A handwritten signature in blue ink, appearing to read 'K. Robertson'.

Keith Robertson
General Manager, Regulatory Policy

Table of contents

Executive Summary	2
MDI A – Resource Adequacy Mechanisms	5
MDI B – Ageing Thermal Generation Strategy	19
MDI C – Essential System Services	19
MDI D – Scheduling and Ahead Mechanisms	25
MDI E – Two-sided Markets	28
MDI F – Valuing Demand Flexibility and Integrating DER	30
MDI G – Transmission Access and the Coordination of Generation and Transmission	31

Executive summary

MDI A – Resource Adequacy Mechanisms

- Approximately 12 GW of the ageing coal fleet is set to retire by 2035, highlighting the significant asset replacement task facing the market. Within the same period, the penetration of variable renewable energy (VRE) is expected to increase markedly and major interconnection projects are being accelerated by governments – all of which will support reliability.
- Notwithstanding this, investment in new flexible dispatchable resources will be required to overcome the timing mismatch between VRE output and demand. A mix of resources (including storage, demand response and thermal plant) that allows for the rebalancing of VRE across multiple timeframes is crucial in ensuring a least cost transition.
- While the NEM has a strong track record in facilitating reliable supply, justifying investment in marginal generation (e.g. gas peakers) has always been challenging – these plants typically rely on a small number of periods per year when capacity is scarce to recover fixed costs. Prospective investors in flexible dispatchable resources now face even greater uncertainty around future revenue potential, driven by changing market dynamics, the impact of government sponsored projects (e.g. Snowy 2.0), accelerated new interconnection, and lower grid demand.
- Given these challenges, there is a clear need to enhance long term investment signals in the NEM with a view to providing greater certainty to both investors and governments. To satisfy this objective at least cost, the ESB should adopt an outcomes-based first principles approach and not be constrained by artificial distinctions between the various frameworks. The proposal to rule out centralised capacity mechanism is confusing, given the preferred options set out in the Consultation Paper are inherently centralised and the advantages of decentralised capacity market frameworks are unproven.
- While an operating reserve could potentially assist with managing reliability/security of supply in real-time, it is unlikely to deliver the requisite level of revenue certainty to de-risk investments. Governments would therefore continue to be reliant on a framework that is expected to facilitate but may not guarantee the required level of investment.
- Decentralised capacity markets like the RRO are too indirect (with the obligation on retailers) and are unproven as a means of delivering timely new investment. A full decentralised capacity market underpinned by physical contracting requirements would also be disruptive, potentially impeding financial contract market liquidity and necessitating changes to current market settings to reduce the market price cap (MPC).
- Having reviewed the options put forward by the ESB, Origin considers a targeted capacity mechanism for new flexible dispatchable resources would provide the revenue certainty needed to justify investment in long lived assets. Importantly, it would also provide a competitive, transparent, and nationally consistent approach that could be used by state governments and/or the market operator to meet jurisdictional reliability targets
- A targeted mechanism would overcome the shortcomings of market-wide capacity frameworks (centralised or decentralised) and drive investment in line with government expectations. To ensure investment in an efficient mix of plant, firmness ratings should be applied to eligible plant. Capacity contracts would likely need to span 7-15 years to support financing. The risk of over procurement (an inherent weakness of capacity mechanisms) and any potential distortionary impacts for existing generation could be managed through the design of the framework.

MDI B – Ageing Thermal Generation Strategy

- The risks associated with generator exit are most effectively managed through the Notification of Closure mechanism and the work being progressed under the resource adequacy and essential system services (ESS) MDIs.
- Generators are incentivised to comply with the current rules, and we do not think it necessary to introduce additional regulatory obligations that could ultimately increase the cost of compliance without achieving any greater level of risk management.

MDI C – Essential System Services

- The ESB has a critical role to play in setting out a consolidated framework to value ESS in an efficient and timely manner. The preference to move toward market-based mechanisms that allow for price discovery and innovation where possible is appropriate in this respect.
- As discussed in the context of the resource adequacy MDI, there is merit in exploring the potential application of operating reserves as a means of managing reliability and security of supply in operational timeframes. Though further clarity is required to understand how the operating reserve would be used/designed in practice, and what gap in security related services it is intended to fill.
- It will be essential to transition to a market-based framework for primary frequency control (PFR) from June 2023 that incentivises voluntary service provision and facilitates the procurement of the most efficient resources. This could be achieved by introducing a new contingency FCAS type service that seeks to maintain frequency more tightly around 50Hz.
- The role of fast acting frequency control services is likely to become more important over time in the NEM. However, there does not appear to be an immediate need to implement a market for fast frequency response (FFR) at this time unless the framework can also be used as a mechanism for procuring inertia.
- A structured approach to procuring system strength that allocates procurement responsibility to AEMO should be progressed as a matter of priority. Joint procurement with inertia should be considered in the event a spot-market based approach to procuring inertia is not achievable in the near term. The application of new mandatory technical limits may also be appropriate, but would need to be carefully designed to ensure they do not perpetuate the kind of issues that have been associated with the existing ‘do no harm’ arrangements.
- A clear pathway toward procuring inertia through real-time markets should be established. As noted above, it may be possible for inertia to be procured through the proposed FFR market, which may provide a useful first step ahead of creating a stand-alone market for inertia.

MDI D – Scheduling and Ahead Mechanisms

- The process around AEMO directions should be streamlined and made more transparent. We therefore support development of the UCS proposal to the extent it will address these issues.
- Origin does not support further consideration of voluntary ahead markets for security services and energy (Options 2 and 3) under the current work program. These options are not a priority and it is not clear they are needed. Additionally, the details around their possible design cannot be determined without first deciding on the underlying approach for the various ESS, which will take some time and should be prioritised, alongside the UCS.

MDI E – Two-sided Markets

- Origin supports steps toward a more two-sided market where progress is likely to be gradual and dictated by the pace of technological change and the willingness of the demand to participate in the market.
- The ESB should provide greater clarity around the scope, rationale, and intended objectives of this MDI. The focus should be on identifying initiatives that could assist in advancing the move towards a two-sided market and ensuring the regulatory framework does not act as a barrier.
- Origin agrees that access to enabling technologies such as smart meters and appropriate tariff structures will be crucial in enhancing customer participation and this should be an ongoing focus.
- It is also unclear how some of the contemplated short-term changes will transition to the longer-term ambition as set out in the Consultation Paper. As an example, the proposal to introduce a new participant category for storage, seems inconsistent with the plan to consolidate and simplify categories in the future.

MDI F – Valuing Demand Flexibility and Integrating DER

- The Consultation Paper rightly highlights that the appropriate integration of DER is a priority. However, to date, the focus of this MDI has not been made clear.
- There is a significant amount of DER-related work underway outside of the ESB process. A starting point should therefore be to identify any gaps and ensure that ultimately the various work streams are focused on achieving a consistent set of objectives.

MDI G – Transmission Access and the Coordination of Generation and Transmission

- The current market transition has been challenging for the grid. The speed at which new connections are occurring is unprecedented. Some generators have been experiencing poorer-than-expected access outcomes such as higher curtailment rates, variable loss factors and connection delays due to stability issues such as system strength.
- To understand and address the root cause of these issues, it is important to take a holistic look at the transmission framework (i.e. generator connections, transmission planning and investment, and network access). However, work in this area has been fragmented which has undermined progress.
- While noting the AEMC is well advanced in developing a new model for network access, it is not prudent to consider implementation at this time. Instead the focus should be on resolving the issues relating to the coordination of generation and transmission investment.
- Origin is concerned the AEMC's plan to introduce locational pricing will result in additional uncertainty and risk that will dissuade new investment and penalise existing plant that cannot alter their location. While the proposal includes some grandfathering arrangements to help manage basis risk for incumbents, this will not go far enough in minimising disruption.
- AEMO's ISP provides the foundation for more efficient coordination by setting a blueprint for the optimal development of the network. To complement the ISP a framework for incorporating REZs should be developed that will look to overcome the first mover and collaboration issues in building connection assets and any required augmentations to the shared network, including for stability services such as system strength.

MDI A – Resource Adequacy Mechanisms

A.1 The NEM faces a significant asset replacement task

A large proportion of coal plant is set to retire by 2035, potentially accelerated by growth in renewables

- [1] With a system that has been predominantly dependent on coal fired generation, the NEM is undergoing a transformative period. Approximately 6 GW of the ageing coal fleet is set to retire by 2030, doubling to 12 GW by 2035. This will be driven by coal generators reaching end of life and worsening economics due to reduced plant dependability and the increasing entry of zero short run marginal cost (SRMC) VRE.
- [2] The Australian Energy Market Operator (AEMO) is forecasting that an additional 6.5 GW of VRE will come online in the next two years alone. Wind and solar generation projects also account for approximately 49 GW (73 per cent) of the 67 GW of new proposed/committed capacity in the NEM. This is unsurprising given renewables now generally provide the least cost form of new electricity supply.¹ Major interconnection projects are also being accelerated by governments to facilitate the expected growth in VRE and allow for sharing of capacity between regions.
- [3] The combination of high VRE penetration and increased interconnection will create a challenging market environment for inflexible plant. As evidenced in South Australia where renewable penetration is already around 50 per cent, VRE has a fundamental impact on market dynamics (see Box 1 below).

Box 1: Impact of high VRE penetration on market dynamics in South Australia²

- While market prices are typically not set by wind generators, the volume of wind generation still has a material impact on spot prices:
 - in 2018-19, 92 per cent of prices above \$1,000/MWh occurred when wind generation was lower than 400 MW; and
 - 87 per cent of the negative prices occurred when wind generation was greater than 1,000 MW.
- SA has observed an increased prevalence of negative price trading intervals from 2015-16 onwards, which coincides with the period in which renewable penetration increased to around 50 per cent in the region following the retirement of Northern power station in May 2016.
- The gap between minimum and maximum operating demand continues to increase, driven principally by the impact of rooftop solar PV. On 10 November 2019, solar PV accounted for 64 per cent of underlying operational demand in the region.

- [4] Capturing value in such an environment will likely require plant to ramp up and down around the VRE generation profile.³ This will have cost implications for inflexible plant that were designed to operate under a continuous 'baseload' profile, given cycling of output can stress equipment and potentially require more frequent maintenance.⁴ These costs are likely to be particularly acute in

¹ AER, "State of the Energy Market 2020", 1 July 2020, pg. 31.

² AEMO, "South Australian Electricity Report", Table 5, November 2019.

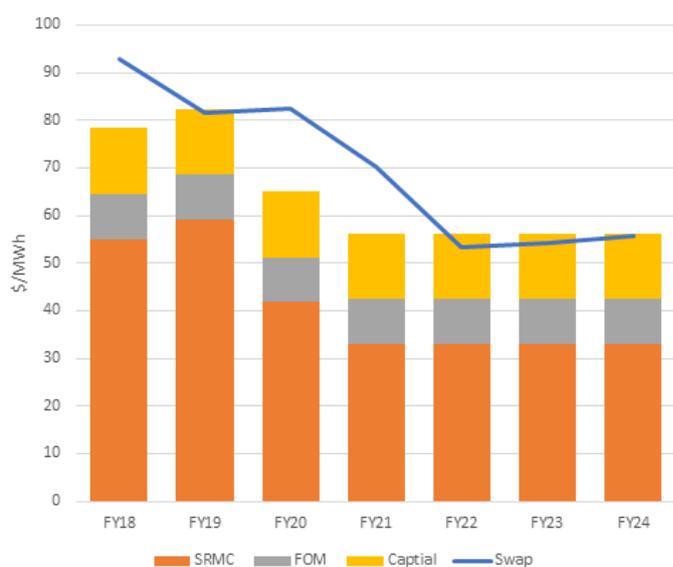
³ Aurora Energy Research, "Aurora Energy Research analysis of AEMO's ISP Part 2: economics of coal closures", Finding 3, May 2019, pg 10.

⁴ Australian Energy Regulator, "State of the Energy Market 2020", 1 July 2020, pg. 36.

the event grid demand drops below the minimum technical operating levels of particular plant.⁵ Lower grid demand is also likely to erode overall revenue potential generally.

[5] Current forward swap prices also make the case for plant life extension challenging. Chart 1 below shows that while recent spot and forward contract prices cover coal plant's short run operating and maintenance costs, there is little room to accommodate significant additional capital expenditure.

Chart 1: Comparison of forward swap price and indicative cost recovery requirements for large coal plant⁶



Box 2: Chart 1 observations

- Chart 1 compares forward swap prices with indicative costs for a large coal-fired plant, including:
 - SRMC based on spot coal prices;
 - typical fixed operation and maintenance (FOM) costs; and
 - additional capex for major maintenance of the type that is likely to be required for some older plant.
- Variable and fixed costs can generally be recovered from a sold swap contract, as well as a return on any major capital spend. However, current forward swap prices may not allow for a return on capital spend if major capex is required over the medium term.

[6] As noted by Aurora Energy Research, the above factors could ultimately accelerate the closure of out-of-merit inflexible plant.⁷ The risk of accelerated closure will increase over time as: plant continues to age and operating/maintenance costs increase; emissions reductions imperatives become stronger; and where the preference for cleaner energy by major lenders / investors / customers / shareholders exerts pressure on the operators of emissions intensive generation.

Investment in firm dispatchable resources will be required to support the transition

[7] Investment in new flexible dispatchable resources will be required to support the expected increase in VRE as coal plant progressively retires. AEMO estimates that about 5-21 GW of capacity will be required over the period to 2040, noting overall resource requirements will be dependent on a range of factors, including the level of interconnection, the timing of coal plant retirements and the level of growth in VRE.

[8] The need for flexible dispatchable resources is principally to overcome the timing mismatch between VRE output and demand. VRE is generally not well correlated with demand and patterns of generation can vary significantly both on a seasonal basis and over shorter time periods.⁸ VRE

⁵ Ibid.

⁶ Origin Energy analysis.

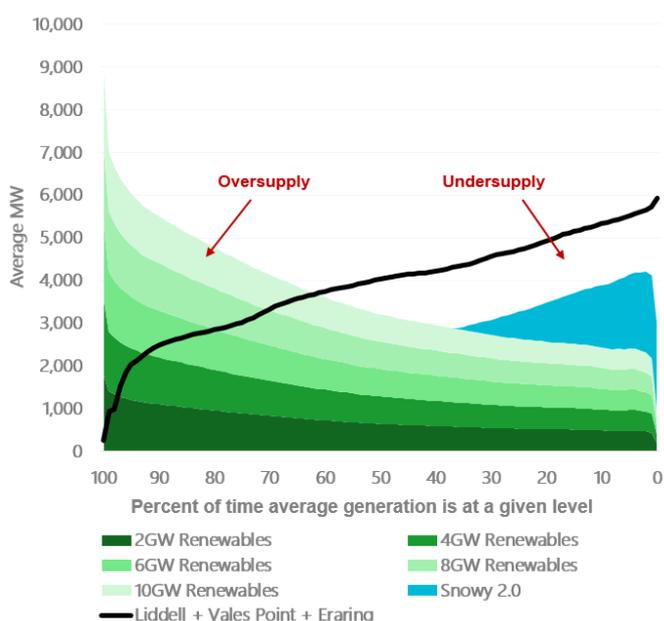
⁷ Aurora Energy Research, "Aurora Energy Research analysis of AEMO's ISP Part 2: economics of coal closures", Finding 3, May 2019, pg 13.

⁸ Oxford Institute for Energy Studies, "Electricity Sector Transition in the National Electricity Market of Australia: Managing Reliability and Security in an Energy-only Market", November 2018, pg. 16.

generators also typically operate below full capacity during periods of peak demand.⁹ In South Australia, VRE contributed less than 10 per cent to demand for the 10 highest demand periods in the region during 2019, relative to their average output of 40 per cent.¹⁰

[9] The inherent mismatch in timing becomes more evident through comparison of VRE operating profiles relative to the dispatchable plant it is expected to replace as set out in Chart 2 below.

Chart 2: Comparison of output duration curves for coal-fired plant and varying levels of VRE in NSW¹¹



Box 3: Chart 2 observations

- Chart 2 compares output duration curves for the three coal-fired generation facilities scheduled to retire in NSW over the period to 2035 (in aggregate), with duration curves for varying levels of VRE.
- The coal plant provides at least 1 GW of capacity at all times (on average), with output generally increasing as operating demand increase. Maximum average output of 6 GW generally coincides with peak demand periods.
- In contrast, VRE has a declining duration curve, which means it cannot precisely replace the energy/capacity profile of the coal facilities when they retire.
- Even with 10 GW of replacement VRE, significant periods of under and over supply will be created that require energy shifting (using storage) and support from other flexible, dispatchable plant.

[10] Interconnection also does not provide a one-for-one substitute for dispatchable resources. While interconnectors can assist with energy sharing, there is still a risk of coincident shortfalls in VRE across different regions. Recent analysis of historical generation profiles undertaken by Global-Roam and Greenview Strategic Consulting found there was no strong statistical evidence to support the statement that ‘it’s always windy or sunny somewhere in the NEM’.¹² Instances were observed where aggregate wind output fell to very low levels across the NEM, despite growth in overall VRE capacity.¹³ Each state will therefore still require its own firm resources.

[11] A mix of flexible dispatchable resources that allows for rebalancing of renewables across multiple timeframes will be required to facilitate the least cost transition. The relative proportion of each resource type will be influenced by both the nature of the asset replacement task across the regions and the differing characteristics (and economics) of the dispatchable technologies. Key considerations in this respect are discussed below.

- Storage (batteries and pumped hydro) is expected to play a significant role in balancing the system by shifting energy from periods of oversupply to when it is needed. The amount of

⁹ AEMO, “2019 Electricity Statement of Opportunities”, August 2019, pg. 3.

¹⁰ Origin Energy analysis.

¹¹ Origin Energy analysis.

¹² Australian Energy Council, “Integrating Renewables: An Assessment of Generation Correlation”, 27 September 2019.

¹³ Ibid.

storage required will be dependent on the duration of oversupply events, which will vary across different timeframes (e.g. hourly, daily, weekly and seasonal).

- While short duration batteries can assist with energy shifting, it is likely to be high cost if used to provide firm supply over multiple days or to manage seasonal variation requirements. This is reflected in assumptions underpinning AEMO's 2020 ISP, where large-scale battery storage is considered in the context of 2-hour and 4-hour depth duration only.
- Pumped hydro is well suited to providing seasonal storage capability. However, costs and available capacity are highly uncertain and site-specific.¹⁴
- Demand response can be used to manage tight supply-demand conditions and reduce the need for involuntary load shedding. Over the longer term, greater demand side participation could also improve the efficiency of dispatch by better revealing the price responsiveness of loads and facilitating the lowest combination of resources to achieve the desired level of reliability.
- Gas power generation, including open cycle gas turbine (OGCT) and combined cycle gas turbine (CCGT) is expected to be needed to support higher levels of storage and renewables across multiple timeframes through the provision of both peak capacity and energy. As with storage, there are trade-offs associated with the different technologies. OCGT is more suited to providing capacity at peak periods while CCGT is more cost effective when running at higher capacity factors.

A.2 Investing in new dispatchable resources will be challenging

Spot market returns have historically been insufficient for marginal plant, given their reliance on highly uncertain scarcity pricing events

- [12] The NEM has a strong track record in facilitating reliable supply, with new generator entry historically following periods of elevated prices. Notwithstanding this, the economics of investing in long-lived capital intensive dispatchable generation has been challenging, particularly for marginal plant. This is principally due to private sector infrastructure investment requiring a level of certainty and stability in forecast cash flows, which can be difficult to achieve in energy-only markets.
- [13] Gas peakers (which have primarily been the marginal plant in the NEM to date), are typically reliant on a relatively small number of periods per year when capacity is scarce to generate revenue. Prices tend to spike under those conditions, exceeding the SRMC of the plant and allowing peaking generators, and by extension all other dispatched generation, to recover their fixed costs.
- [14] To justify investment in marginal plant, prices at times of scarcity must be high enough and occur with sufficient frequency to provide a suitable return on investment. This has not historically been the case for firm peaking capacity in the NEM. Origin estimates average spot market revenue achieved for OCGT plant operating over the period from 2010 to be approximately \$8.30/MWh. Relative to annualised new build costs of around \$15.67/MWh, this equates to an average revenue shortfall in the order of \$7.37/MWh for OCGT plant.

¹⁴ AEMO, "Building power system resilience with pumped hydro energy storage", July 2019, pg. 21.

- [15] While cap contracts can provide peaking generation with additional revenue, typically these do not materially improve the case for investment. Cap prices generally reflect underlying spot market volatility, which is greatest during low probability of occurrence events (e.g. extreme weather periods). This makes cap returns highly variable and difficult to predict. Further, as identified in the Consultation Paper, customers are generally unwilling to enter into contracts with durations beyond around two years, which again is not long enough to support new investment.
- [16] Given the above factors, recent investment in dispatchable generation has in large part been driven by vertically integrated retailers (rather than merchant generation), most likely to manage the exposure of retail load to the wholesale spot price. By creating a natural hedge, vertical integration generally provides retailers with additional flexibility to manage the volume risk of under/over contracting. Linking generation output with retail customers also provides certainty to financiers and increases their propensity to lend.
- [17] In the absence of longer-term certainty around revenue and risk allocation, whether it be provided through vertical integration or through contracting arrangements, willingness to underwrite investment in marginal generation capacity under a merchant generator model are reduced. As noted by PWC in the context of funding renewable energy projects, merchant projects with greater price and operational risk exposure find it difficult to raise debt and will therefore attract a higher weighted average cost of capital (WACC).¹⁵ Cash-flow certainty is also reduced, which can make it difficult to meet debt repayment schedules.¹⁶

Market signals for new dispatchable resources may not be strong enough to ensure the required level of investment in line with government expectations of reliability

- [18] Noting the historical challenges identified above, prospective investors in flexible dispatchable resources now face an even greater level of uncertainty around future revenue potential. This uncertainty is ultimately being driven by the broad range of factors identified in the Consultation Paper, not least of which are discussed below.

Changing market dynamics will increase uncertainty

- [19] As discussed in Section A.1, growth in VRE will have a fundamental impact on wholesale market outcomes. It will likely become increasingly more difficult for dispatchable plant to predict and capture periods of higher prices in order to recover fixed costs.
- [20] There is also significant uncertainty around the duration and frequency of future price spikes. AEMO has noted that the current influx of renewables will reduce wholesale prices in some of the periods that flexible capacity currently operates.¹⁷ Modelling undertaken by the AER demonstrated that the general uplift in prices observed during 2017-18 (i.e. following the closure of Hazelwood power station) had not translated to the price spikes required to support low capacity factor technologies such as OCGT.¹⁸ The spot price exceeded \$300/MWh on only 205 occasions in 2017–18, compared with 688 occasions in 2016–17 and 555 occasions in 2015–16.¹⁹
- [21] The expected change in market dynamics will create investment challenges for all forms of dispatchable generation, including utility scale storage. Storage technology will have a relative

¹⁵ PWC, "Is merchant the new black?", May 2018, pg. 1.

¹⁶ Oxford Institute for Energy Studies, "Electricity Sector Transition in the National Electricity Market of Australia: Managing Reliability and Security in an Energy-only Market", November 2018, pg. 15.

¹⁷ AEMO, "Observations: Operational and market challenges to reliability and security in the NEM", March 2018, pg. 34.

¹⁸ AER, "Wholesale electricity market performance report", December 2018, pg. 57.

¹⁹ Ibid, pg. 11.

advantage over fast-start thermal plant to the extent that it can derive additional value through arbitrage between high and low prices. However, PWC recently assessed the economics of utility scale storage and noted the current regulatory framework makes it difficult for investors and financiers to 'bank' storage projects.²⁰ This is principally due to the unpredictability of future prices (including over short run timeframes) and resultant lack of certainty and stability in cash flows.²¹ PWC further noted it is not actually possible to include the full revenue potential from price spike events in financiers' project cash flow projections for storage, given the ability of storage to access those periods may conflict with a typical 'time of day' trading strategy.²²

Outlook for NEM operating demand

[22] Historically, all electricity was produced by large scale generators and supplied to end use customers through the transmission/distribution grid. Coupled with a stable large manufacturing / industrial customer base, this manifested in relatively predictable demand growth over the period to 2008-09,²³ which was conducive to long term investment. Since that time, grid demand has declined at an average annual rate of 1.7 per cent²⁴ over the five year period to 30 June 2014 and has remained relatively flat over the subsequent period to 2019-20.²⁵ The future level of operating demand to be served by the centralised system is unclear, given uncertainty around the ongoing uptake of DER, the scale of energy efficiency improvements and the longevity of major industrial loads (some of which are dependent on government subsidy), noting smelter loads represent around 8 per cent and 10 per cent of annual consumption in Victoria and NSW respectively.²⁶ This lack of clarity can undermine the business case for investment in centralised resources generally.

Investment in major government sponsored projects

[23] Substantial investment in interconnection and other major projects (e.g. Snowy 2.0 and 'Battery of the Nation') are currently being considered/progressed. While increased interconnection is vital in managing a system with greater levels of VRE, it can also dissuade investment in dispatchable plant with an interconnector essentially serving as a competitor to native generation within NEM regions. AEMO has also identified that with Snowy 2.0 now committed, market signals for additional pumped hydro investment are likely to be weak until further significant coal-fired generation closures occur (i.e. in the late 2020s to mid-2030s).²⁷

[24] More generally, policy uncertainty and government intervention were highlighted in the AER's 2018 Wholesale Market Performance Report as key issues that can make investment in the NEM more challenging. Opaque mechanisms such as the Commonwealth Government's Underwriting New Generation Investment (UNGI) mechanism create significant uncertainty and risk for prospective investors.

[25] Government policy initiatives have also demonstrated a preference for higher levels of reliability and investment than the existing market framework is designed to deliver. This is evidenced by the Commonwealth Government's announcement that an additional 1,000 MW of dispatchable generation is required in NSW by summer 2023-24 and will be delivered by Snowy Hydro if private sector investment is not committed by April 2021. Given ASX quarterly cap contracts in NSW are

²⁰ PWC, "Energy Storage – Financing speedbumps and opportunities", February 2019, pg. 4.

²¹ Ibid.

²² Ibid, pg. 7.

²³ Australian Energy Regulator, 'State of the Energy Market 2018', December 2018, pg. 74.

²⁴ AER, 'State of the Energy Market 2015', December 2015, pg. 24.

²⁵ AER, 'State of the Energy Market 2020', Figure 2.2, 1 July 2020, pg. 71.

²⁶ Origin Energy analysis.

²⁷ Ibid, pg. 6.

currently trading at around \$6/MWh²⁸ relative to estimated new build costs of \$15.67/MWh, market-based signals for investment in the requested capacity are likely to be subdued.

A.3 Assessment of options to ensure reliability of supply

- [26] Given the challenges identified above, Origin supports consideration of reform options that will assist with providing greater certainty to both investors and governments, which is key to achieving the requisite level of resource adequacy. The threat of government intervention can be self-fulfilling, given it has the effect of discouraging private sector investment and ultimately providing added motivation for governments to step in. The interdependence between investor and government confidence should therefore be explicitly considered and serve as the starting point when contemplating reform choices.
- [27] While noting that much of the detail is yet to be worked through, Origin's initial view is the options proposed in the Consultation Paper are unlikely to adequately satisfy these key objectives. As discussed further below, the proposed operating reserve and modified RRO framework are unlikely to assist with de-risking future investment and providing governments with certainty around the level and timing of new resource capacity.

To enhance long term investment signals the ESB should adopt a first principles outcomes based approach

- [28] We urge the ESB to adopt a first principles outcomes-based approach that is not constrained by artificial distinctions between various groups of options. The proposal to explicitly rule out centralised capacity mechanisms at this stage is confusing, given both preferred choices (i.e. the operating reserves and Retailer Reliability Obligation (RRO)) are inherently centralised in nature. As highlighted in the earlier sections of this submission and acknowledged by the ESB, there is a clear need to enhance long term investment signals in the NEM. The complete spectrum of design choices should therefore be examined.
- [29] Origin is not advocating for a centralised capacity mechanism in the traditional sense, but we believe there is an opportunity to tailor an approach that is suited to the NEM. As discussed further below, a targeted framework for new flexible dispatchable capacity could provide a greater level of certainty for both investors and governments while minimising the pitfalls of both decentralised and centralised mechanisms.

An operating reserve could potentially assist with managing reliability/security of supply in real-time, but is unlikely to support new investment

- [30] The operating reserve has been described as a mechanism that could be used to achieve two potential objectives: improving short-term operational signals; and strengthening longer term investment signals through upward pressure on the energy price. In Origin's view, it is not clear the first objective needs addressing, and the second is unlikely to be achieved.
- Short-term reliability signals: Origin agrees there is merit in exploring the potential application of an operating reserve as a means of managing reliability/security of supply in operational timeframes and lessening reliance on out-of-market mechanisms (such as the RERT). However, further analysis is required to clarify the challenge the operating reserve is

²⁸ ASX, 'Energy Derivatives – Australian Electricity', website, accessed 16 October 2020.

expected to resolve in operational timeframes, particularly as it relates to the provision of generation capacity.

The Consultation Paper appears to suggest that an operating reserve would facilitate the provision of spare MW's that are potentially not being made available to the market. This premise is inconsistent with the fact that there are very few AEMO directions for reliability, which indicates current scarcity pricing provides adequate incentives for all resources to be available in an operational timeframe when needed to support demand. This contrasts with some US markets, where the absence of effective scarcity pricing signals (driven by relatively low market caps) has necessitated the use of operating reserves.

If the intent is to facilitate higher levels of demand response within the market, then this would most likely require higher prices. Otherwise demand response providers would continue to preference participation in the RERT due to the higher remuneration potential and additional revenue certainty provided through availability payments under that framework. In any case it is unlikely that both the operating reserves and RERT can (or should) co-exist, given they would each be looking to attract similar resources.

- Longer-term investment signals: It appears the operating reserve would enable the energy price to reach the MPC sooner at some pre-defined reserve margin. This seems analogous to increasing the MPC and could suffer from similar challenges in terms of improving investment signals. Prospective investors in flexible dispatchable resources would still face uncertainty around the value (i.e. the frequency and magnitude of price spikes) that could be derived from energy and reserve markets in the future. Unless the operating reserve could facilitate a more certain revenue stream, the mechanism is unlikely to assist new entrants in securing financing.

When considering long term incentives, the operating reserves is no different (at least in its intent) to a capacity mechanism for dispatchable resources. While the operating reserves could seek to offer availability payments which would enhance the similarities with a capacity market, critically a capacity mechanism would provide payments over an extended period long enough to directly support new investment, while the operating reserve would not.

The operating reserve would also not provide governments with any additional assurance around future levels of investment and the timing of replacement capacity following major coal-plant retirements. The risk of ongoing government intervention is therefore not resolved through this option. As is currently the case with the MPC, governments may also be unwilling to allow the reserve market to be designed in a way that allows for any meaningful uplift in energy prices on an ongoing basis. Where energy market revenue potential remains materially below the true value of customer reliability (VCR) (the NEM-wide estimate for which is \$40,990/MWh²⁹), market-based signals for new investment are likely to remain weak.

[31] Given the above, it is important the ESB provides additional clarity around the challenges an operating reserve is expected to resolve and how it could be used/designed to achieve that objective in practice. Areas for clarification include:

- the specific use case for operating reserves;

²⁹ AER, "Values of Customer Reliability – Final report on VCR values", December 2019, Table 5.22.

- the type of product(s) that would need to be procured through the mechanism to meet the desired objective, and circumstances under which the reserve would be used for either reliability or security purposes;
- how the operating reserve would be priced and why this is a superior approach to simply increasing the MPC; and
- how the costs associated with procuring/dispatching reserve capacity could be allocated to market participants, noting a causer pay's approach would be preferable.

[32] The ESB should also undertake an assessment of the overall cost of implementing the operating reserve. The Consultation Paper suggests that given co-optimisation of frequency control ancillary service (FCAS) markets already takes place in the NEM, implementation of an operating reserve may be less complex than in some US markets where the system changes have been costly. Experience with recent major reforms in the NEM has demonstrated there are always unforeseen complexities that can give rise to substantial costs for both AEMO and market participants. In particular, the costs associated with implementing five minute settlement are now substantially above original estimates. The wholesale demand response mechanism was also re-designed relatively late in the AEMC's rule change process to mitigate costs/complexity concerns that weren't initially foreseen. It should therefore not be assumed that implementing an operating reserve framework would be simple change.

Capacity market frameworks can support longer term investment signals, but the purported advantages of decentralised capacity market frameworks are unproven

[33] As noted earlier, the ESB does not support giving further consideration to a centralised capacity market on the basis it would fundamentally shift risk allocation relative to existing arrangements and presents no obvious benefits over a decentralised capacity market. In Origin's view, the purported advantages of decentralised procurement frameworks relative to centralised frameworks from a general risk allocation perspective are not evident. Under both approaches over procurement risk is partially shifted from generators to the designated central authority (and consequently consumers), albeit through retailers in the case of decentralised frameworks.

[34] The Consultation Paper argues that allocating risk to retailers would facilitate more efficient outcomes since retailers would have flexibility around how they meet their obligation (e.g. with their own contracting / hedging approach). However, as discussed further below in the context of the RRO, this merely highlights the inherent risk that such a mechanism may not meet the key objective of driving new investment.

[35] Both frameworks also rely on centralised decision making to determine key parameters that impact the level of risk allocation, including procurement targets/obligations; procurement time frames; eligibility; and penalty provisions. Centralised decision making is also fundamental to the operating reserve, given it would rely on the setting of administratively determined reserve targets and prices.

[36] With respect to potential benefits, centralised capacity markets provide the most direct means of ensuring resource adequacy and can be used to facilitate a certain level of reliability over a specified time horizon in line with market requirements and government expectations. This contrasts with decentralised frameworks, where market settings and obligations on retailers are intended to facilitate (but not guarantee) the required level of investment.

An enhanced RRO/decentralised capacity market framework is unlikely to provide an efficient or effective solution to facilitating new investment

- [37] The objective of expanding the RRO along the spectrum toward a decentralised capacity market would be to improve incentives for long term contracting to support new investment. In practice, Origin does not believe an enhanced RRO will achieve the intended purpose.

The RRO is too indirect and uncertain

- [38] The RRO and decentralised capacity markets more broadly, provide a relatively indirect (and consequently uncertain) means of facilitating new investment: Under such frameworks, a retailer's obligation (which is intended to drive new investment) is dependent on factors such as the uncertain nature and timing of its contracting with commercial and industrial (C&I) customers. C&I load is highly variable, as these customers tend to enter relatively short-term contracting arrangements with retailers and churn regularly. There is also uncertainty around the longevity of major industrial loads and the outlook for grid demand more broadly. It would therefore be challenging and impractical for retailers to enter into longer-term financial contracts or directly underwrite investment in long-lived generation assets to support C&I load.
- [39] Changing the nature of the retailer obligation (e.g. by increasing the level to which retailers are required to contract and/or requiring contracts to be supported by physical generation capacity) will not resolve this fundamental issue, or provide governments with assurance that the requisite level of investment will occur in a timely manner. Consideration could be given to placing the obligation on large customers directly, but we note that this was met with opposition when the RRO was first designed. While large loads can opt into the mechanism, it is our understanding that this has not been widely taken up, if at all.

Requiring contracts to be physically back could undermine risk management

- [40] Requiring contracts to be backed by physical generation would likely discourage participation in the ASX futures market (which currently accounts for a significant volume of contract trading activity). This could reduce wholesale contract market liquidity and result in market participants deviating from their optimal risk management strategies, which would have cost implications for consumers. It would also disadvantage non-vertically integrated retailers, potentially impeding their ability to compete for C&I customer demand. These factors were a key driver for not requiring physical backing of eligible contracts under the existing RRO framework.

A full decentralised capacity market would be disruptive and provide limited price certainty for consumers or investors

- [41] The Consultation Paper states that a decentralised capacity market could be used to remunerate capacity that "*is only used very rarely and without a separate revenue stream or allowing unacceptably high real-time prices, will not be provided by the market.*"³⁰ However, a decentralised market-wide mechanism would provide increased revenue potential for *all* existing dispatchable resources. This could lead to windfall gains for existing generators that were likely to be operating regardless of the additional revenue stream and potentially weaken signals for new investment. As identified in the Consultation Paper, this would likely necessitate changes to the current market settings to reduce the MPC and other market caps³¹.
- [42] Decentralised market frameworks also rely on signalling scarcity through the value of defined certificates/contracts, similar to the Large-scale Renewable Energy Target (LRET). Experience with the LRET demonstrated that certificate prices tend to trend towards the tax adjusted penalty rate when they are expected to be in short supply, with certificates providing little value when the

³⁰ ESB, 'Post 2025 Market Design Consultation Paper', September 2020, pg. 41.

³¹ Ibid.

target is expected to be met. This somewhat binary pricing behaviour leads to cost variability for large and residential customers alike, noting regulators currently base regulated retail prices on short term market price forecasts. An investor looking to capture the scarcity value of certificates (should that signal arise) would also have no revenue certainty to support new investment.

Decentralised mechanisms are unproven in delivering new investment

- [43] Experience with international markets does not demonstrate a compelling case for relying on an enhanced RRO / decentralised capacity market framework. The French capacity market is a decentralised, market-wide mechanism that was introduced in 2017 to ensure generation capacity is made available during volatile winter peak demand periods. Consistent with the modifications described above, the French mechanism requires retailers to buy 'capacity certificates' from generators or demand response providers to cover their respective share of peak demand on an annual basis. In theory, the mechanism could indirectly incentivise new investment in flexible resources if scarce capacity drives high certificate prices. However, there is little evidence that this has occurred in practice. The market operator RTE observed that while the mechanism has led to some investment in demand response capacity, it has also prolonged the life of some existing plant.³²
- [44] Given the above limitations, a separate targeted mechanism was introduced in France in 2019 aimed at incentivising new investment in cleaner, flexible plant through the provision of fixed price contracts over a seven year period. So far this has delivered 253 MW of battery storage and 124 MW of demand response.

A targeted capacity market framework would provide the certainty necessary to support new investment in line with government expectations while minimising costs for consumers

- [45] A targeted mechanism for new firm dispatchable resources could overcome the shortcomings of market-wide frameworks (centralised or decentralised) and ensure future investment needs are met. The provision of payments for capacity over defined forward periods would provide the additional revenue certainty necessary to support new investment in dispatchable resources.

A targeted mechanism would make the cost of meeting reliability objectives more transparent

- [46] A key benefit of a targeted mechanism is that it would provide a more transparent and uniform framework for delivering the desired level of reliability to meet the needs of the system and in line with government expectations. This contrasts with the energy only-market framework of the NEM and decentralised capacity market frameworks more broadly. The targeted mechanism would therefore mitigate the risk of ongoing ad-hoc government interventions and remove the need to rely on other opaque mechanisms such as the UNGI program. Importantly, it would also ensure State/Territory Governments are more accountable for the costs associated with any reliability related decisions in their respective regions.
- [47] Providing a forward auction for new capacity would reduce the risk of price shocks that can be associated with the exit of large plant, as evidenced by the retirement of Hazelwood in 2017.³³ This should in turn allow for a smoother market transition and provide governments with confidence around the timing of replacement capacity. Relative to a decentralised certificate-based scheme, it would also reduce overall price variability for consumers.

³² <https://lemag.rte-et-vous.com/actualites/tout-ce-que-vous-avez-toujours-voulu-savoir-sur-le-mecanisme-de-capacite>.

³³ AER, "Electricity wholesale performance monitoring – Hazelwood advice", March 2018.

Risks can be more effectively managed under a targeted mechanism compared to a market-wide approach

- [48] Over-procurement risk is more likely to be heightened under market-wide frameworks that do not adequately account for relevant externalities (e.g. emissions, dispatchability) and remunerate existing capacity providers on an ongoing basis. This contrasts with a targeted mechanism, which would only give rise to additional costs when the mechanism is triggered (in a given region) and limit those costs to the procurement of a smaller volume of capacity (i.e. costs would be limited to overcoming the 'missing money' associated with new investment only). Where market signals are sufficient to support investment, the mechanism will not need to be triggered.

The impact on existing generation is likely to be limited but could be managed in any case

- [49] A potential trade-off associated with the targeted capacity mechanism is that it would introduce an additional revenue stream for new capacity providers that is not available to incumbents. In Origin's view, the volume and type of capacity that would be delivered through the mechanism is unlikely to materially impact bid stack dynamics. Flexible dispatchable resources are likely to remain the marginal plant in the NEM and sit at the top of the bid stack. The risk of the mechanism accelerating the closure of coal plant that generally sit lower down the bid stack is therefore likely to be limited.
- [50] To the extent there are concerns around potential distortionary impacts, an option to address this could be to prohibit any resources that receive capacity payments under the targeted mechanism from participating in any operating reserve market for energy. The operating reserve and targeted capacity mechanism both seek to provide additional revenue for flexible, dispatchable resources. The key difference between the two is the timescale for procurement, with the targeted mechanism providing the longer-term certainty required to facilitate new investment. Limiting access to the operating reserve would therefore provide incumbent resources with an additional revenue stream and ensure a level playing field with any new capacity delivered through the targeted mechanism.

A targeted mechanism would be compatible with other potential reforms

- [51] Valuing ESS, or the establishment of an operating reserve would not negate or undermine the need for a targeted mechanism. Such reforms could potentially complement a forward capacity market (e.g. opportunities for further revenues in the real-time markets would likely lead to lower capacity prices; and in the event additional revenue available through real time markets can assist with facilitating new investment, this would reduce reliance on the targeted mechanism).
- [52] Further, no change to existing market settings would likely be required, since only a small proportion of the market would be accessing the mechanism. The need for less transparent and relatively high-cost backstop mechanisms such as long-notice RERT and the Interim Reliability Measure would also be reduced.

Table 1: Summary assessment – market reform options

Principles	Operating reserve	Enhanced RRO / Decentralised capacity market	Targeted capacity mechanism
Efficient investment signals to support reliability and security of supply	<ul style="list-style-type: none"> An operating reserve could potentially assist with supporting system reliability/security and reducing reliance on (and the need for) backstop mechanisms such as the RERT. However, further clarity is needed to understand the objective and design of the reserve. [?] Long-term investment signals are unlikely to be materially improved. [✖] As noted by FTI Consulting, the operating reserve could increase revenue potential for existing resources, which may weaken incentives for new investment. [?] 	<ul style="list-style-type: none"> Incentives for retailers to underwrite new investment to support a proportion of maximum demand are likely to remain weak, given uncertainty around C&I customer demand and the broader outlook for NEM demand. [✖] Requiring contracts to be backed by physical generation could impede contract market liquidity. Non-vertically integrated retailers are likely to be disadvantaged. [✖] An inability to secure physical supply may impede retailers' ability to compete for C&I customers. [✖] Market-wide mechanisms can lead to windfall gains for existing generators and weaken investment signals. [✖] An investor looking to capture the scarcity value of contracts backed by physical generation capacity (should that signal arise) would still have no long-term revenue certainty to support new investment. [✖] A reduction in market price caps may be required, which would undermine the intent of the proposed operating reserve. [?] 	<ul style="list-style-type: none"> The mechanism would directly support new investment, including merchant generation. [✓] Procurement volumes could be set to ensure investment requirements are aligned with government/consumer expectations for reliability. [✓] No change to existing market settings would likely be required. The mechanism would be compatible with other reforms being considered. [✓] The need for less transparent and relatively high-cost backstop mechanisms would be removed. [✓] Bid stack dynamics are unlikely to be materially impacted. Any concerns could also be managed by restricting access to the proposed operating reserve. [✓] Limiting access to new resources would avoid creating windfall gains. [✓]
Appropriate risk allocation	<ul style="list-style-type: none"> Some over-procurement risk transferred to retailers/consumers. Risks/costs would depend on centrally determined targets and pre-defined price curves. [?] 	<ul style="list-style-type: none"> Some over-procurement risk transferred to retailers/consumers. Risks/costs would depend on centrally determined targets and obligations. [?] 	<ul style="list-style-type: none"> Some over-procurement risk transferred to retailers/consumers. Risks/costs would depend on centrally determined targets and obligations. [?]
No undue discrimination	<ul style="list-style-type: none"> Flexible resources are likely to receive greater benefit, though co-optimisation with energy would increase revenue potential for all resources dispatched in the energy market. [✓] 	<ul style="list-style-type: none"> Market-wide frameworks create additional revenue streams for all dispatchable resources, regardless of externalities such as emissions and dispatchability. [✖] 	<ul style="list-style-type: none"> The market could directly incentivise investment in resources necessary to complement VRE growth, having regard to relevant externalities such as emissions and dispatchability. [✓]
Minimum regulatory intervention	<ul style="list-style-type: none"> Regulatory intervention would be required to set key parameters, including reserve targets and the value of reserve capacity. Key parameters would also require regular updating. [?] Risk of ongoing intervention is high, given governments would be reliant on market settings facilitating (but not guaranteeing) the required level of investment. [✖] 	<ul style="list-style-type: none"> Regulatory intervention would be required to set key parameters, including procurement targets/obligations; procurement time frames; eligibility; and penalty provisions. [?] Risk of ongoing intervention is high, given governments would be reliant on market settings and obligations on retailers facilitating (but not guaranteeing) the required level of investment. [✖] 	<ul style="list-style-type: none"> Regulatory intervention would be required to set key parameters, including procurement targets/obligations; procurement time frames; eligibility; and penalty provisions. [?] Investor sentiment would be strengthened by the transparent and uniform framework for delivering resource capacity in line with Government expectations. [✓] The mechanism would establish a greater level of accountability around the costs of government decisions. [✓]

A.4 How a targeted mechanism could work in practice

Essential features of a targeted mechanism

[53] The targeted mechanism would need to be carefully designed to facilitate the right type of investment, but at a high level we expect it could incorporate the following features.

- Access to the mechanism: Access would be limited to new firm capacity only. A technology neutral approach subject to firmness and minimum environmental standards would be applied.
- Identifying a capacity shortfall: AEMO's Electricity Statement of Opportunities (ESOO) could be used to identify a capacity/energy shortfall 3-5 years ahead of time. This is broadly consistent with approaches applied across a range of international markets that rely on setting a capacity requirement and holding an auction 3-4 years ahead of the capacity delivery period.
- Setting the requirement: State Government's would be responsible for setting the capacity procurement requirement (based on the identified shortfall) and establishing the firmness ratings and environment standards to be applied to eligible technologies. Firmness ratings would be used to ensure the state government tenders for the 'right' type of technology with a view to minimising over-build risk and overall costs for consumers. A least cost solution will be one that minimises the 'delivered' cost of energy (e.g. MWh) for consumers. As such, in determining firmness ratings, consideration would need to be given to the capabilities of different technologies both from a capacity and energy perspective.
- Auction for capacity: A reverse auction would be conducted to determine a common clearing price for capacity and award contracts to address the identified shortfall. Origin's expectation is that auction participants would factor expected spot market revenue into their capacity bids, which would ensure capacity providers continue to bear investment risk and reduce potential cost impacts for consumers relative to market-wide mechanisms. The competitive process would drive least cost outcomes.
- Duration of capacity contracts: The duration of contracts allocated through the mechanism must provide prospective investors with the certainty required to support new build. While the market-wide mechanism in the PJM only awards annual contracts, several other key markets make longer-term contracts available to new capacity providers. These include ISO-NE, Ireland and the UK, which provide 7, 10- and 15-year contracts respectively for new build. In Origin's view, contracting periods under the targeted mechanism would likely need to span similar timeframes, noting short-term contracts are unlikely to provide the requisite level of certainty for investors.
- Capacity payment structures: Capacity payments could be allocated to contracted providers (at the fixed price determined through the auction) on a monthly basis over the length of the contract period.
- Cost recovery: A levy on market loads within the impacted region could be applied over the term of the contracting periods.
- Penalty framework for non-delivery: A robust penalty framework for non-delivery could be established to ensure capacity procured through the mechanism is built and made available as required. This would overcome some of the issues observed internationally where: capacity contracts awarded through an auction have been cancelled prior to the delivery

period due to a project failing to obtain financial backing; and/or capacity is not made available during contracted periods due to weak penalty rates.

MDI B – Ageing Thermal Generator Strategy

B.1 The risks associated with plant closure are best managed through existing rules and other work being undertaken by the ESB

- [54] Origin considers it most appropriate to manage any risks associated with generator closure through the existing regulatory framework and the work being progressed under the Resource Adequacy and ESS programs.
- [55] In 2018 the AEMC introduced a requirement for generators to provide 42 months' notice before exiting the market. Exemptions from the notification requirement are only available in the event of unforeseen circumstances such as a technical failure.
- [56] We also note that asset owners will face significant costs if a generator exits before the expected date. In the event of an unforeseen closure, the asset owner may struggle to meet its contract obligations; be required to bring forward decommissioning costs; and face reputational risk. Therefore, it is often in the asset owner's interest that a generator remains in the market until the committed date.
- [57] The ESB's work on ESS will be important in helping to safeguard against premature plant exit by providing a value stream and additional revenue for services some thermal plant current supply to the market for free.
- [58] Similarly, the development of appropriate options under the Resource Adequacy MDI is crucial in minimising any adverse impacts of thermal plant exit such as prolonged price shocks. As we have set out in the previous section, enhancing long term investment signals through appropriate measures is necessary to ensure the entry of replacement dispatchable generation over time. Any base level of uncertainty around plant exits can also be managed by increasingly stringent reliability standards which will dictate that there is a higher reserve margin (i.e. dispatchable resources) across NEM regions.
- [59] Given the above, and that generators are incentivised to comply with the current rules, we do not think it is necessary for the ESB to contemplate the introduction of additional regulatory obligations, that ultimately could increase the cost of compliance without achieving any greater level of risk management.

MDI C – Essential System Services

C.1 A transparent and enduring framework for the provision of ESS is required

- [60] Synchronous generators have historically provided a range of essential system services (ESS) as a by-product of energy generation. As the stock of synchronous plant declines and the entry of non-synchronous resources increases, the management of the power system is becoming more challenging. AEMO has expressed concerns around the NEM's declining frequency performance and is now reliant on market directions and the imposition of caps on renewable generation levels in some regions to manage system strength.

- [61] To address these issues a raft of new measures have been introduced including the mandatory provision of primary frequency response (PFR) (on a transitional basis), and an obligation on transmission network service providers (TNSPs) to procure minimum levels of inertia. Generators are also now subject to a 'do no harm' framework to support system strength. These reforms, though well intentioned, do not represent efficient long-term solutions given their reliance on mandatory service provision and the absence of clear incentives / investment signals for service provision.
- [62] The ESB's review therefore has a critical role to play in setting out a consolidated framework to value ESS in an efficient and timely manner. Origin supports the ESB's preference to move toward market-based mechanisms that allow for price discovery and innovation. By pricing these services, generators that currently provide them for free can recover costs, and will be incentivised to supply, helping to stabilise the system.
- [63] Given the inherent characteristics of different services, a range of market solutions will need to be considered, and the relative need for each may necessitate a staged approach to delivery. Key issues that will therefore need to be addressed in developing solutions include:
- whether the service identified is required, and in what timeframe (i.e. should its delivery be prioritised);
 - how the service should be procured, having regard to the nature of the service and if any transitional steps are required;
 - whether the service allows for co-optimisation with energy and/or other services; and
 - how the costs associated with remunerating the service should be recovered.
- [64] It is in this context that Origin has provided comment on the high-level ESS design solutions put forward by the ESB, as discussed below.

C.2 Operating reserves

- [65] Consistent with the discussion outlined in response to the resource adequacy MDI, Origin considers there is merit in exploring the potential application of operating reserves as a means of managing reliability and security of supply in operational timeframes. However, further clarity is needed to understand how the operating reserve would be used/designed in practice, as well as what gap in security related services the reserve is expected to fill.

The nature of any operating reserves will need to be defined

- [66] The Consultation Paper suggests the purpose of the operating reserve is to manage variability in supply/demand, including net demand ramp events caused by large changes in VRE that may span several dispatch intervals. AEMO's 2020 Renewable Integration Study projects the largest downward VRE ramp in the NEM will reach -4.5 GW (over one hour) by 2025, compared with -1.4 GW historically.³⁴
- [67] A potential gap in existing arrangements that could be addressed by an operating reserve in this context is the provision of tertiary frequency control type services (e.g. 10min/30min products)

³⁴ AEMO, 'Renewable Integration Study Stage 1 Report', April 2020, pg. 57.

that are currently used in some US markets³⁵. Nonetheless, it is important that additional analysis is undertaken to demonstrate that a service of this nature is required to manage the system (i.e. to allow AEMO to return the system to a secure operating state following a contingency event). This analysis should consider:

- whether operational signals are likely to be insufficient to support the provision of ramping capacity by the market following a contingency event, having regard to the impact of the resource adequacy framework reforms discussed earlier (which is intended to drive further investment in flexible dispatchable plant that can assist with managing ramping events), and potential valuation of other ESS; and
- the design of the products that could be procured through the operating reserve. This includes how the products would be priced, and how AEMO would be expected to determine that procurement of reserve capacity beyond a minimum necessary level would lead to more efficient market outcomes.

C.3 Frequency control services

Primary frequency response

[68] Origin is strongly supportive of transitioning to a market-based framework for PFR from June 2023 that incentivises voluntary provision of the service and facilitates the procurement of the most efficient resources, consistent with the workplan set out by the AEMC.

Transitioning to a market based approach for PFR is crucial

[69] The current mandatory approach imposes costs on all generators (including those not well placed to provide the service) and fails to balance the cost of service provision with overall system security benefits. It also provides no incentive for new entrants to invest in PFR and potentially reduces the value of existing contingency services.³⁶ This could have the unintended consequence of signalling to participants that frequency response is less valued by the market, leading to a lack of investment in FCAS capability more broadly.

[70] As outlined in a recent paper prepared by the Australian Energy Council, a market for PFR could be established by introducing a new contingency FCAS type service for narrow dead band raise and lower response that seeks to maintain frequency more tightly around 50Hz.³⁷ Changes to the frequency operating standard (FOS) would likely be required to guide the procurement of PFR volumes, noting the FOS only specifies the boundaries of the Normal Operating Frequency Band (NOFB), not how frequency needs to be managed within the NOFB. Resources could then bid to provide PFR reserves (which would effectively represent headroom in MWs) and be enabled for service provision ahead of time consistent with existing FCAS arrangements.

[71] The costs associated with PFR service provision could likely be recovered on an equivalent basis to existing contingency or regulation FCAS services. However, further consideration would need to be given to the most efficient approach, noting limitations with the existing FCAS causer-pays framework have been identified by the AEMC and are currently being considered through the System Service Rule Changes workstream.

35

³⁶ AEMC, 'Mandatory Primary Frequency Response – Final Determination', 26 March 2020, pg. 81.

³⁷ AEC, 'Economic procurement of Primary Frequency Response', September 2020.

Fast frequency response

[72] Origin agrees the role of fast acting frequency control services in the NEM is likely to become more important over time, given these services can assist with managing high Rate of Change of Frequency (RoCoF) events and operating the power system at lower levels of inertia. As noted by the AEMC in its Final Determination on Managing the Rate of Change of Power System Frequency, co-optimisation of inertia and FFR service provision may also lower the cost of managing system RoCoF.

There may not be an immediate need to implement a market for FFR

[73] The introduction of a new FFR category within the existing FCAS regime may be regarded as a relatively incremental approach to addressing this issue. However, such a market would not overcome the need to establish a transparent framework for incentivising the provision of inertia, given FFR is not a perfect substitute. Further, any net benefits associated with establishing an FFR market in the near term are likely to be dependent on:

- the efficacy of the PRF rule change and any subsequent revisions to the PFR framework to remunerate service provision – improved PFR performance will likely reduce the volume of FFR required;
- the extent to which the service could be competitively procured – at present, a narrow response time (e.g. within 2s) would limit the pool of providers;
- the broader framework for procuring FCAS – in the absence of a holistic review of existing FCAS categories, introducing a new category could lead to inefficient procurement/use of FCAS services more broadly; and
- the broader framework for procuring inertia – incentivising the provision of inertia will reduce the volume of FFR required.

[74] Noting the above factors, Origin does not consider there is a material need to implement an FFR market in the near term. It would also be prudent to undertake a more holistic review of the FCAS framework to consider whether existing settings and/or market structures could be revised to better accommodate the provision of faster acting services rather than immediately introducing a new FCAS category.

A procurement approach that allows for bundling of FFR and inertia should be considered

[75] The case for implementing an FFR market in the near term may however be improved if the framework could be designed to procure and remunerate both inertial response (natural and synthetic) and fast acting services under the Market Ancillary Services Specification (MASS). This approach would establish a framework for incentivising investment in faster acting frequency control services that are expected to be needed in the future. More importantly, it would provide an initial step toward establishing a real-time market for inertia service provision (if needed), with the FFR market likely to be mostly supplied with natural inertial response, at least initially. This would likely reduce AEMO's reliance on out-of-market contracting for inertia (discussed further below), since synchronous generators would have greater financial incentive to remain self-committed during low inertia periods, potentially even when energy prices are low.

[76] If the above framework is technically feasible, the FFR rule change process currently being progressed by the AEMC could be used to prioritise the design/development of such a market. A transitional path toward splitting out inertia service provision into a stand-alone real-time spot

market could also be established by the ESB, which may ultimately be required to provide a more explicit signal for the service.

A comprehensive review of the broader frequency framework may be required in the future

- [77] Any implementation timeframes associated with FFR should ideally also allow time to consider:
- if any resultant refinements to the existing FCAS framework are necessary, particularly given other potential changes to PFR service provision;
 - whether there are any operational uncertainties associated with the provision of non-inertial fast acting frequency services that would need to be managed by AEMO (e.g. the impact of rapid injections of active power on system security); and
 - the development of a RoCoF standard that could be used to guide the procurement of FFR/inertia volumes.
- [78] More broadly, the Consultation Paper also outlines the potential end-goal for FCAS could be to transition to a framework that allows the for procurement of frequency response beyond minimum levels using demand curves. This would represent a significant design change relative to the existing FCAS framework. Consideration would therefore need to be given to whether:
- the existing arrangements that target procurement levels relative to a pre-defined standard are likely to give rise to any material inefficiencies; as noted above with respect to the operating reserve;
 - how AEMO would be expected to assess the economic trade-offs associated with procuring additional frequency control service would lead to more efficient outcomes;
 - and how the costs associated with the service would be allocated to market participants.

C.4 Synchronous services – system strength and inertia

System strength

A structured approach to procuring system strength that allocates procurement responsibility to AEMO should be progressed as a matter of priority

- [79] Origin supports the ESB's preference to move towards real-time markets for service provision where the system and technologies allow, noting this will provide the clearest price signals to prospective investors. In the context of system strength, it is clear this is unlikely to be achievable in the near term based on the nature of the serve (i.e. it is difficult to define/measure, and requirements are often localised). There is also a need to progress reforms to the existing system strength framework as a matter of priority to address the current ad-hoc approach to procurement and issues being observed in the market.
- [80] Given the above factors, Origin supports a centrally coordinated approach that would allow AEMO to procure system strength through contracts with providers. This would lessen the reliance on directions and help with the transition away from the current do no harm provisions that have proven to be inefficient. Importantly with AEMO as the procurer, this will enable generators and TNSPs to compete for service provision on an equitable basis.

- [81] AEMO's ISP could potentially be used as a tool to identify emerging system strength issues over investment timeframes. To guide procurement, it would also be important to ensure appropriate standards for system strength are developed, possibly by the Reliability Panel. Further, a transparent reporting framework would need to be established to ensure the costs are visible to the market with a view to providing a transparent investment signal for future service provision.
- [82] Implementation of the above framework could be prioritised by leveraging the TransGrid rule change proposal currently being considered by the AEMC. The TransGrid proposal seeks to abolish the existing 'do no harm' provisions and allow TNSP's to be more proactive in the provision of system strength in the NEM. It should therefore provide the AEMC with adequate scope to develop a preferred rule that establishes a structured approach to procurement of system strength, with procurement responsibility allocated to AEMO.

Joint procurement with inertia should be considered in the event a spot-market based approach to procuring inertia is not achievable in the near term

- [83] As noted in the consultation paper, an alternate solution that has been put forward is to allow for the joint procurement of synchronous services by AEMO that could be used to satisfy multiple objectives (e.g. system strength and inertia). If the ESB determines a structured approach to procurement is appropriate for both system strength and inertia, joint procurement could potentially provide some efficiency benefits, particularly where those services are being procured from the same resource or group of resources. However, procurement levels under this approach would still need to be underpinned by appropriate standards and a transparent reporting framework.

The application of new mandatory technical limits may be appropriate, but would need to be carefully designed to avoid introducing further inefficiencies

- [84] It may be appropriate to also consider whether there are mandatory technical limits that could be applied to complement the above framework. As touched on in the Consultation Paper, this could include requirements for new projects to invest in inverters that are able to maintain stable operation in an environment of lower system strength, which would potentially reduce the need for AEMO to take actions to mitigate shortfalls. However, it would be important to ensure that any new technical limits do not perpetuate the kind of issues that have been associated with the existing 'do no harm' arrangements.

Inertia

A pathway toward procuring inertia through real-time markets should be established

- [85] Origin is supportive of the ESB developing a clear pathway toward procuring inertia through real-time markets. As identified in the consultation paper, inertia is quantifiable and can be procured on a global basis, which increases the scope for competitive service provision across the NEM. The reform process currently underway in the Western Australian Electricity Market (WEM) to establish a RoCoF control service also provides evidence that real-time markets for inertia are achievable.³⁸
- [86] As discussed earlier, it may be possible for inertia to be procured through the proposed FFR market, noting inertia and fast acting frequency services more broadly are generally used to meet the same objective (i.e. to manage RoCoF). If this is achievable, it may provide a useful first step

³⁸ Energy Transformation Implementation Unit, 'Transformation Design and Operation Working Group Meeting 11, 29 April 2020.

toward valuing inertia through a real-time market that avoids the need to create a stand-alone market, at least initially.

- [87] To the extent procurement through real-time markets is not an achievable first step, a structured approach similar to that described above for system strength could be applied for inertia. This would also represent an improvement relative to the existing framework that allocates responsibility for meeting minimum inertia requirements solely to TNSPs. As discussed above, consideration could then be given to whether joint procurement of inertia and system strength is appropriate.

C.5 Regulatory framework changes

- [88] Origin does not consider there is a need to provide AEMO and TNSPs with additional regulatory flexibility as the market transitions. The current regulatory framework provides AEMO with adequate flexibility to undertake trials that can be used to gain practical experience and test technical capabilities, as evidenced with initiatives that have been undertaken to assess frequency performance. The use of guidelines and procedures also provides AEMO with additional discretion in the way it implements specific rules, and it is appropriate that the AEMC continues to be responsible for determining when/where that discretion should be provided.
- [89] If further flexibility is to be introduced into the regulatory framework, it will be important for the ESB to clarify where and why it is needed. Appropriate checks and balances would also need to be introduced to ensure adequate levels of accountability are retained.

MDI D – Scheduling and ahead mechanisms

- [90] The Consultation Paper sets out the ESB's rationale for introducing some level of 'aheadness' in the NEM. Origin agrees ahead mechanisms that allow for operational decisions to be made in advance of real time could assist AEMO in managing the market. However, in determining where on the spectrum of design options is ideal, it is important to examine the underlying reasoning being put forward in support of ahead markets and the possible trade-offs involved. When looking at all the relevant factors, Origin's view is that the ESB's focus should be on the development of Option 1 –UCS.

D.1 An examination of the possible rationale for ahead mechanisms in the NEM reinforces that extreme design options are not required

- [91] Limit use of interventions: The ESB rightly highlights that the growing reliance on market interventions is due to a lack of prices for ESS and the advanced notice period required by some synchronous generation when providing these services. However, it is not ahead mechanisms, but rather the establishment of a value stream (and consequently price signals) for ESS that is key to limiting interventions such as AEMO directions. Services procured through structured contracts (e.g. system strength) could also include requirements specifying notice times, minimising the need for this issue to be resolved through an ahead market.
- [92] Address uncertainty in pre-dispatch: The Consultation Paper cites the differences between pre-dispatch and real-time prices as evidence of the growing uncertainty in the market, which presents challenges for both AEMO and market participants. From Origin's perspective, any divergence between the two prices has been primarily driven by: the increased penetration of VRE capacity, which can face challenges following pre-dispatch commitments given the variable nature of their fuel source; and an increase in the size and number of AEMO demand forecast revisions. Given this, it is doubtful that any of the ahead market design initiatives can actively combat these issues.

- [93] Incentivise demand response (DR): Given the lead time required, it has been suggested that an ahead market could facilitate the scheduling and consequently increased utilisation of demand response and slow start plant. While it is important to maximise the potential of demand response, any overscheduling of resources ahead of time will come at a cost, reducing market efficiency
- [94] Greater operational control for the market operator: The NEM already has similar features to an ahead market (e.g. generators are incentivised to make efficient self-commitment decisions (i.e. make plant available) to defend their contracted positions, which helps to ensure reliability, minimising the need for directions. A self-commitment approach keeps risk with generators that are best placed to manage this through their own portfolios. Shifting to a greater level of centralised commitment gives the market operator more operational control but shifts this risk. Fundamentally, the centralised commitment model is no different from the current directions process. The market operator may also need to recover additional payments to cover the costs of inefficient scheduling.
- [95] Ahead Schedules. There are additional risks when giving individual units a financially binding schedule ahead of time. For example, the cold start of a thermal unit is risky due to the increased likelihood of technical issues. In this scenario a generator would not want to be financially bound to a specific start time. The market operator may also be forced to increase interventions if it becomes reliant on risky units that cannot meet their schedules.

D.2 Examining the Design Options

- [96] Origin agrees the current process around AEMO directions should be streamlined and made more transparent. We therefore support further development of the UCS proposal to the extent it will address these issues. We note, however, there is still a great deal of detail that needs to be worked through, and we suggest this is prioritised ahead of any further exploration of Options 2 and 3. We do not consider the case for implementing the System Service Ahead Scheduling and Integrated Ahead Markets has been made. We also agree with the decision to not pursue a mandatory ahead market. We provide some specific comments on each Option below.

Option 1: UCS – should be implemented subject to appropriate design

- Cost information. The UCS design appears to call for the collection of technical and economic information to determine least-cost interventions and to remunerate directed participants. In considering the design detail the ESB should remain cognisant of the challenges in standardising generator costs. One issue with the current process is the difficulty in recovering important portfolio or opportunity costs that provide a complete view of the imposts incurred by generators following a market direction. While it may be simple to verify the physical costs of starting a unit, this does not fully represent the true cost to the generator which is determined by several factors, including the number of starts remaining before scheduled maintenance, and access to fuel. The current remuneration process requires independent consultants to verify additional costs claimed by directed participants, which can prove administratively challenging. An appropriate cost methodology should therefore be developed as part of the UCS design that accounts for all relevant factors.
- Activating Structured Security Contracts. The UCS appears to have two roles – a new directions protocol and the scheduling of contracted services. The usefulness of the UCS as a scheduling tool cannot be evaluated without first determining the nature of these contracts. Origin recommends the ESB work on the design of the contracted services before completing this feature of the UCS design.

There is also a suggestion the UCS could be used to activate additional service contracts beyond the minimum level required to maintain system security. Origin considers AEMO's role is to maintain the system by procuring and scheduling the level of ESS needed to keep the market in a secure state. Anything beyond this could result in the operator unduly influencing market outcomes. It is also unclear on what basis any additional ESS would be procured or how these costs would be apportioned.

- Intervention Pricing. Origin agrees intervention pricing should apply to any services impacted by the UCS that are normally scheduled through a spot market. We note that as service contracts are not considered out-of-market interventions they will not trigger intervention pricing. However, where RERT is deemed to be a service contract, its deployment should initiate intervention pricing, as this impacts the market price for energy.
- Timing of Interventions under the UCS. Without understanding the procurement approach for the ESS, it is difficult to assess the potential timeframes for intervention. Any timeframes should work in tandem with security services and allow for the greatest market response wherever possible.

The process for reassessing and remunerating altered directions needs to be fully understood and developed. Changing the nature of an earlier direction could mean that generators are unable to recover their operating costs.

Option 2: System Service Ahead Scheduling – should not be pursued

[97] Origin does not support further consideration of System Service Ahead Scheduling under the NEM 2025 program as this option is not a priority and it is not clear that it is needed. The details around any possible design also cannot be determined without first deciding on the underlying approach for the various ESS, which will take some time and should therefore be prioritised.

[98] In our view some of the suggested rationale for pursuing this option is not compelling and is discussed in greater detail below.

- Hedging System Services: A proposed benefit of System Service Ahead Scheduling is the ability to hedge any security service costs. The procurement approach and cost allocation methodology for the various ESS have not been finalised and will have some bearing on whether there will be a desire to hedge any associated costs. Additionally, if the need for hedging eventuates, market participants may choose to manage their exposure to the cost of ESS through longer term contractual arrangements rather than on an ahead basis.
- System Services without Real-Time Prices: The Consultation Paper suggests that security services procured under a structured contract could also be made available through an ahead market, which could enable competitive tension. The logic or practicality of this approach is not obvious and runs the risk of undermining incentives for contracting. It has only been hypothesised, and not demonstrated, why creating an ahead market on-top of a structured procurement model would provide any benefits.

Option 3: Integrated Ahead Market – should not be pursued

[99] For similar reasons set out in the discussion on Option 2, Origin does not support further development of an Integrated Ahead Market under the current work program. Additionally, if an ahead market was implemented for energy, this could disrupt the nature of financial contracts. Even if contracts continued to reference the real-time spot price, there is likely to be significant implications for generators who may now also be required to alter their behaviour to manage their ahead market schedule.

[100] One suggested benefit of Option 3 is that it could enable greater levels of co-optimisation. It remains unclear how this would work, and what costs are involved, including any required changes to the dispatch engine. The paper also does not discuss the trade-offs of co-optimisation in real-time as opposed to in an ahead timeframe, with the latter being automatically assumed to be the superior option. The benefits of co-optimisation are also limited in a voluntary market as only those resources that choose to participate would be included.

MDI E – Two-sided markets

[101] The initial supply side focus at market start reflected the technological capability at the time. However, as technology improves and new types of generation and demand response become more commonplace, the opportunity exists to more effectively incorporate the demand side into the NEM framework. Origin therefore supports progressive steps toward a more two-sided market that has the potential to increase customer choice and sharpen price signals, ultimately lowering system costs.

[102] At this point, the timing and extent to which these (or any other) benefits are likely to be realised is unclear and dependent on where the market ends up on the continuum of possible futures. Progress will be dictated by the robustness of the regulatory regime as exhibited by the ability to adapt to the changing environment, and perhaps more importantly by the pace of technological advancement and innovation.

E.1 Greater clarity is needed around the scope of the work program

[103] Notwithstanding the lack of clarity around the pace of change, Origin considers it important for the ESB to provide greater clarity around the scope, rationale, and intended objectives of this MDI. In our view, the focus should be on identifying initiatives that could assist in advancing the move towards a two-sided market and ensuring the regulatory framework does not act as a barrier. Crucially, when contemplating possible measures, the trade-offs should be examined and only those that result in net benefits should be pursued.

Transitional pathway is uncertain, but perhaps inherently so given the nature of the changes

[104] While the Consultation Paper sets out proposed changes over three timeframes, it is not clear what the rationale was for the timing chosen. Without further examination of the potential size of the market, technological trends and consumer uptake, it is difficult to assess if the timelines chosen are optimal.

[105] It is also unclear how some of the contemplated short-term changes will transition to the longer term ambition as set out in the Paper. As an example, the proposal to introduce a new participant category for storage, seems inconsistent with the plan to consolidate and simplify categories in the future. The wholesale demand response mechanism, while consistent in principle, also takes a different approach to a two-sided market by introducing a new category. It would not be pragmatic to move away from newly-introduced mechanisms, concepts and obligations only a few years after they have been implemented.

[106] The ESB should therefore identify a clear and pragmatic transition plan as it continues to develop a two-sided market, which accounts for the likely size of the market, and when it may be optimal to make changes. Categorising any designated stages as indicative and highlighting the factors that could have a bearing on progression will help to clear up confusion and improve transparency of the MDI.

The possible role of the regulatory framework in enhancing customer participation should be defined, but it is important to acknowledge that innovation and customer choice is key

[107] Origin agrees that access to enabling technologies such as smart meters and appropriate tariff structures will be crucial in enhancing customer participation and this should be an ongoing focus.

[108] The consultation paper also states that other complementary measures may also be appropriate to support improving outcomes to consumers who may not have the means, ability or motivation to engage in new market offerings. It is not clear, however, what those measures would be or if it is being suggested that these issues can be addressed through regulation. It should be left to product developers to innovate and offer solutions that consumers want, which will encourage participation. There is evidence that this is already happening. Origin recently launched ‘Spike’, a demand response program that rewards our customers for reducing or shifting demand. In order to incentivise participation, the program takes the innovative approach of gamifying demand response, thereby providing a simple, fun and low-barrier option for consumers to be involved in the market.

The two-sided market work should be integrated with relevant sections of the DER MDI

[109] We note the overlap with the DER MDI. The changes to participant categories and scheduling would also capture DER given that it is a form of demand-side participation. We therefore suggest the ESB merge the wholesale integration aspects of the DER MDI with the two-sided market work, to the extent that there is not already a plan to do so.

The proposed short term measures should only progress if they are addressing material issues

[110] The specific short-term measures proposed by the ESB in the consultation paper should only be progressed if material problems are identified. For example, it is not clear from the paper what the issue with the current small generator aggregator framework is. It is also unclear how the two-sided market work is being coordinated with the short-term options proposed – many of the options involve ongoing projects being completed by other market bodies, rather by the ESB itself. More detail on this aspect would be welcome.

It is unclear if consolidation of participant categories will improve efficiency

[111] The ESB also proposes to move away from participant categories based on technologies in the medium-to-long term, and introduce obligations and responsibilities based on the type of service offered. We consider this could be beneficial if it reduces complexity and promotes better integration of the demand side, while future proofing against the introduction of new technologies. However, such a move would also likely be costly due to the complexity of the change itself. It is also unclear if the existing framework is a major deterrent to demand-side integration.

[112] Further, it is not evident whether moving towards the concept of “users” and “traders” would reduce complexity in practice. The ESB should continue to work on identifying how much granularity will still be needed in a simplified participation framework to account for the distinct characteristics and capabilities of the different types of technologies.

The trade-offs in enhancing scheduling obligations for load will need to be examined

[113] We understand the ESB is considering a “scheduled lite” option whereby the demand side would face less stringent obligations than scheduled loads do. Looser obligations may increase participation but at the expense of some of the benefits of pure scheduling (e.g. more efficient pricing). In considering changes to obligations, the ESB should first identify the key barriers to participation and what the net benefits of scheduling in a “light” manner would be.

MDI F – Valuing Demand Flexibility and Integrating DER

- [114] The Consultation Paper rightly highlights that the appropriate integration of DER is a priority for the NEM going forward. However, to date, the focus of this MDI has not been made clear. Origin notes there is a significant amount of DER-related work underway outside of the ESB process. A starting point should therefore be to identify any gaps and ensure that ultimately the various work streams are focused on achieving a consistent set of objectives.
- [115] Origin suggests that to allow DER owners to gain the most value from their participation, the integration approach should follow a series of principles, as outlined below:
- Consumer led implementation: Frameworks for market integration of DER should minimise both complexity and cost for the owners of the systems. Consumers should be able to control their level of interaction with the market. Other parties, such as network businesses, should not be able to place requirements on the operation of DER in a way that impedes the ability of the DER owner to maximise return from the service they provide.
 - Encourage competition for services: Some DER technologies are still in their early phase of development and roll-out. Further innovation will be encouraged by the creation of new markets and mechanisms for providers to unlock value from the services provided.
 - Ensure competitive neutrality for all businesses: Monopoly network businesses can include DER used primarily for network support in their regulatory asset bases. Where network owned assets can participate in the wholesale market this could place other DER providers at a relative disadvantage, consequently discouraging innovation and participation. To encourage competition, network-owned or controlled assets should not be able to take part in the broader market.
 - National consistency: Having inconsistent regulatory regimes places extra costs on equipment suppliers, market participants and end customers. We note that South Australia recently introduced jurisdictional specific requirements to manage security risks of solar systems. Going forward, it would be ideal for such issues to be resolved through a nationally consistent approach.

F.1 ESB should look to build on the role of retailers and aggregators in facilitating DER

- [116] Retailers and aggregators play a key role DER integration in the market and policy settings should encourage greater innovation and product development which is already occurring. Some of Origin's recent new product offerings have been in the areas of solar & storage and connected homes. We currently have over 85 MW of demand response capability through our virtual power plant (VPP) platform which enables the coordination of a range of behind the meter DER including EVs, electric hot water, solar and battery storage. The platform uses artificial intelligence to learn and predict the behaviour of energy consumers and optimises each of the assets based on this learned behaviour and enables customers to have a greater degree of choice when selecting a connected home solution.

F.2 A balance of technical and market signals is needed

- [117] DER should be encouraged to participate in the market particularly at times when the service they provide are of most value. However, to ensure the security of the system, it is necessary for a baseline of regulatory requirements to be in place. It will be crucial to find the balance that will allow DER to respond to market signals, thereby encouraging investment and innovation while

also ensuring it operates in a predictable manner in line with the technical requirements of the system.

[118] The goal of providing economically efficient signals should be balanced against practical considerations. Notably, the administrative cost of determining the impact of any specific DER can be significant compared to the incremental impact on the network, especially for smaller systems. The ESB should ensure that any signals based on estimates of average impact do not place undue costs on smaller systems, and lead to unintended costs.

MDI G – Transmission Access and the Coordination of Generation and Transmission

[119] The current market transition has been challenging for the grid. The speed at which new connections are occurring is unprecedented, and the generation mix is rapidly changing from a small number of large generators, to a larger number of smaller entrants. There have also been well-publicised issues in areas such as North Western Victoria where some generators have had a large proportion of their capacity curtailed while others have been queued for connection. Origin considers that to understand and address the root causes of these issues, it is important to take a holistic look at the transmission framework (i.e. generator connections; transmission planning and investment and; network access).

G.1 Transmission framework

[120] Origin is concerned the fragmented nature of work in this area has undermined the development of a coordinated and effective approach in tackling the transmission related challenges facing the market. As AEMO continues to develop the ISP that will now govern planning and investment, the AEMC has been pursuing changes to the access regime, with the ESB now looking at establishing a framework for REZs. While the AEMC is well advanced in developing a new model for network access, in our view it is not prudent to consider implementation before resolving the issues relating to the coordination of generation and transmission investment.

Table 2: Summary of key issues associated with the transmission framework

Elements of the transmission framework	Issues to consider
<p>Generator connections and entry: The nature of generation investment is shifting, with a larger number of smaller generators looking to connect more often.</p> <p>Historically, strong locational signals, including the prospect of being constrained off (due to network congestion) and incurring greater transmission losses, have generally worked well. Some generators are now seemingly making sub-optimal and irrational locational decisions, impacting access.</p>	<ul style="list-style-type: none"> ▪ The nature of new entry has amplified the need for a coordinated approach to generation and transmission investment. This is particularly so given incentives (e.g. renewable energy targets) can guide investment to areas with little spare transmission ▪ Given the already dire consequences of locating in congested areas, increasing the punitive nature of locational signals is not the key to driving more efficient behaviour
<p>Transmission planning and investment: The previous jurisdictional-led approach did not adequately allow for a national/strategic outlook and needed changes to support increased interconnection and renewables development in a coordinated manner.</p>	<ul style="list-style-type: none"> ▪ The ISP provides the foundation for more efficient coordination by setting a blueprint for the optimal development of the network. ▪ To complement the ISP a framework for incorporating REZs should be developed that will look to overcome the first mover and collaboration issues in building

<p>The continual development of the ISP means the planning process for transmission has become more unified and strategic, with changes made to ensure that augmentation occurs in a timely manner. The ISP also identifies REZs, which highlight potential siting locations for new entrants.</p>	<p>connection assets and any required augmentations to the shared network, including system strength.</p> <ul style="list-style-type: none"> ▪ AEMO’s Interactive Map published for the 2020 ISP could also be enhanced (e.g. by providing more detailed forecasts of congestion). ▪ AEMO through the ISP identifies emerging system strength issues over investment timeframes which will improve transparency for new entrants. This could further be improved by being accompanied by a robust framework for the procurement of system strength (as being contemplated under the ESS MDI) ▪ The above measures should help to resolve the timing mismatch between generation and transmission investment by providing clarity around what generators are entering the market
<p>Network access: Historically, the NEM’s open access regime has worked well. More recently, some generators have been experiencing poorer-than-expected access outcomes such as higher curtailment rates, variable loss factors and connection delays due to stability issues such as system strength.</p> <p>The AEMC considers the cause of these problems is that locational signals do not adequately incentivise new generators to make use of existing and new transmission capacity.</p>	<ul style="list-style-type: none"> ▪ The proposal to introduce locational pricing implies that this is key to addressing access concerns. ▪ Instead, access-related issues, such as higher than expected curtailment rates are symptoms of inefficient coordination with network upgrades sometimes lagging generation.

G.2 The proposed changes to the access regime

COGATI does not address coordination

[121] Despite its name, the AEMC’s Coordination of Generation and Transmission Investment (COGATI) model does not address the key issues relating to the lack of coordination of generation and transmission investment. Nor does it deal with the technical barriers (such as low system strength) that arise due to increased renewables penetration.

[122] The recently announced Victorian renewable energy target (VRET2) is an example of where government policy will provide locational signals for investors to site generation in areas of the network that is rich in renewables. However, these can be in parts of the grid that are already seeing connection and congestion issues. Grid upgrades in those areas are currently not planned for many years, if planned at all, highlighting the current disconnect between network planning, government planning and generation investment.

[123] Even if augmentation is brought forward in the next ISP, without a clear framework for coordinating transmission and generation investment, there is a risk new projects will continue to face connection delays and curtailment.

COGATI introduces additional uncertainty and risk

[124] There is also concern COGATI will introduce additional uncertainty and risk that will dissuade new investment and penalise existing plant that cannot alter their location. While the proposal includes some grandfathering arrangements, they do not go far enough to minimise disruption. Table 3 below discusses some of the trade-offs involved with the proposal.

Table 3: Summary of trade-offs associated with the proposed access model

Current arrangements	Proposed approach	Implications for the market
Pricing		
Five zonal prices – generators and load face the same regional price.	<ul style="list-style-type: none"> More than 1000 local prices – most generators face the local price while most load face a type of regional price. 	<ul style="list-style-type: none"> More granular prices could sharpen locational signals. However, they also introduce basis (price) risk where there is divergence between the local and regional reference prices. This is problematic given financial contracts in the NEM are linked to the regional price. The implications for the financial market are an ongoing concern, as the prospect of re-opening contracts such as power purchasing agreements (PPAs) would prove disruptive.
Managing congestion risk		
Managed by generators through forecasts of congestion.	<ul style="list-style-type: none"> Congestion risk is managed using a hedging mechanism through financial transmission rights (FTRs) for a number of pre-defined nodes. 	<ul style="list-style-type: none"> FTRs are being proposed to manage the basis risk introduced by the model (as generators will no longer face the regional price). However, there continues to be concerns about the firmness of FTRs and their ability to fully manage basis risk, despite several changes being made to the model to improve revenue adequacy. The need to manage basis risk also creates an added layer of complexity by needing to forecast the amount and price of FTRs. It should also be noted that FTRs are introduced to manage a risk that is created through nodal pricing – generators can, and already do manage congestion (volume) risk without the need for any complex framework.
Network losses		
Static marginal annual losses	<ul style="list-style-type: none"> Dynamic marginal losses (changes every five minutes instead of annually). 	<ul style="list-style-type: none"> Moving to dynamic marginal loss factors (MLFs) would improve accuracy but would be more difficult to manage. Some generators are already struggling with the changes in static MLFs adjusted annually. Dynamic MLFs that change every five minutes would be challenging to forecast. The proposal does not include FTRs for dynamic losses, which means that this additional risk would remain unhedged.

G.3 Proposed path forward

The immediate focus should be on resolving coordination issues

[125] It would be premature to make significant changes to the access regime before we have resolved coordination issues and understood the underlying drivers of siting decisions. Origin therefore suggests the ESB:

- Examine the drivers behind locational decisions by proponents (in particular, renewables). This should include the impact of state-based renewable energy targets.

- Determine the impact of the recent changes aimed at improving transparency for developers and new entrants (e.g. the transparency of new projects rule change and AEMO's interactive map for the 2020 ISP).
- Develop the REZ framework as a matter of priority, coordinated with the AEMC's work on dedicated connection assets.
- Finalise the process for projects that have been earmarked for development in the current ISP

The need for broad access reform should only be considered once coordination issues have been resolved.

[126] Once coordination issues have been addressed, the National Energy Cabinet could then re-assess the need for changes to the access regime such as those being contemplated by the AEMC.