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Monday, 19 October 2020

Dr Kerry Schott AO
Chair
Energy Security Board

Dear Dr Schott

RE: Post-2025 Market Design Consultation Paper

ERM Power Retail Pty Ltd (ERM Power) welcomes the opportunity to respond to the Energy Security Board's (ESB) post-2025 Market Design consultation paper.

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

http://www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

General Comments

ERM Power commends the ESB on the work it has done so far to investigate the issues relating to the post-2025 market design review. We consider that the results of this review will help to create a fit-for-purpose market design that supports the security and reliability of the National Electricity Market (NEM) while ensuring lower electricity prices for consumers. Ideally, the reforms that arise from this review could also help to end the cycle of competing rule changes and policy reform that has been a hallmark of the past few years of energy policy. In many cases, these changes have sought to address overlapping issues or have claimed vast benefits without adequate and compelling quantitative work to support these claims.

ERM Power does not believe that major reform of the NEM is required. On the whole, we believe the current market design provides the necessary framework and the right signals for supply to be available, for users to make the decision to consume or not, and in conjunction with a range of planning documents, for generation to be built when required. However, it does not correctly value the full range of services needed to keep the system secure. Given the scale of change in the energy sector with more renewables and distributed energy coming online, we see that there is a strong case for some incremental reforms to the NEM, in order to deliver improved reliability and security, and better incentivise firm and flexible generation.

[1] Based on ERM Power analysis of latest published information.

In particular, we consider that there are a range of new system services, like inertia and fast frequency response, that can be scheduled and dispatched via a real-time market, similar to the existing ancillary services markets. This will allow the NEM to support greater volumes of renewable energy and provide new markets for all kinds of generation technologies to deliver the kinds of power system services needed to keep the NEM secure.

We acknowledge that there is a real concern from policymakers that there won't be enough firm capacity available at key times in some states. For this reason, we have developed two approaches that we believe will address these concerns at a far lower cost than the ESB's mooted approach of adjusting the Retailer Reliability Obligation. These approaches would deliver additional new capacity if the Australian Energy Market Operator's forecasts suggest additional new capacity above that already committed is needed. Further, we consider that the notice of closure arrangements for generators could be strengthened to improve the signals for investors to deliver new generation when it is needed.

Crucially, we see that these kinds of incremental changes can work with the existing market frameworks and, where possible, provide market-based solutions to provide the required services. By working alongside the existing market structure, there is little work needed to be done to redesign systems – AEMO's or market participants' – to adjust to the new market design. This would also reduce the risks associated with multiple major systems changes occurring at the same time.

ERM Power considers the overall model we have set out, which builds on many of the ESB's own proposals, provides the right signals and mechanisms to adjust to change as required. It can be adjusted as need be to deal with further changes to market dynamics and the kinds of technologies entering the energy market. For instance, the penetration of new technologies like electric vehicles, battery storage or some other new technology is extremely difficult to forecast, both in timing and volume. The huge volumes of solar PV installed in Australia since 2010 shows just how fast things can change. Increasing volumes of Distributed Energy Resources (DER) may create the need for additional adjustments to manage the changing volumes and flows of energy. Provided the settings and market design are designed in a way that is robust to change, then any changes required to deal with more DER can be developed and implemented relatively quickly and smoothly if managed effectively.

In addition, we support the ESB's move to stagger these reforms over the coming years rather than pursue a hard start date for a number of changes. This will certainly reduce the costs and risks associated with changing systems to cater for a range of potentially large changes to internal and market systems that take effect at the same time. It will also allow the ESB, or other market bodies to observe changes progressively and to assess whether additional changes are indeed required.

For the most part, ERM Power considers the ESB is on the right track in developing reforms for each of the market design initiatives. We believe that the ESB's preferences to not pursue certain approaches like mandatory day ahead markets and a full two-sided market with bidding for demand and supply are sound decisions. The voluntary approaches that the ESB outlines in the consultation paper appear, in our view, to be more suitable to address the issues that the ESB has identified as needing solutions. We agree with the ESB's view to pursue market-based solutions for essential services where possible.

Finally, we remain unconvinced by the rationale for the Coordination of Generation and Transmission Infrastructure reforms. The reform creates significant risks and investment uncertainty resulting in disruption to existing long-term energy contracts and added costs for market participants due to the Locational Marginal Pricing regime being proposed.

We are concerned the reform no longer attempts to address the key question posed by the COAG Energy Council of improved coordination of generation and transmission investment. Despite the key original justification for the COGATI, the proposed reform is instead aimed at modifying scheduled participants access to the regional reference price for settlement.

We look forward to continuing to engage with the ESB over the coming months as it delivers its final report to energy ministers and over the coming years as it moves towards implementation of some significant reforms to the NEM. Comments on each of the market design initiatives are contained in the submission that follows.

Our Regulatory team stands ready to discuss and support this submission with your officers to ensure understanding, discuss further and co-develop proposals contained therein.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

Greg Joiner
CEO ERM Power and VP Shell Energy Australia

Resource Adequacy Mechanisms

ERM Power acknowledges the concerns that the ESB and others hold about sufficient firm or dispatchable capacity being available at key times to ensure reliability of the system. As thermal capacity exits the market in coming years, concerns may increase. However, we note that the 2020 Electricity Statement of Opportunities (ESOO) does not show a forecast breach of the reliability standard (0.002 per cent unserved energy) in the NEM until 2029-30 in New South Wales when Vales Point is scheduled to close. The forecast 'shortage' of capacity before then is based on the Interim Reliability Measure's (IRM) far lower 0.0006 per cent unserved energy (USE) metric and in our view only occurs due to a significant volume of forecast new generation projects not as yet meeting AEMO's "committed" status although many are noted by AEMO as at the "advanced" stage.

Given the current very high level of reliability in the system, any changes to improve reliability are likely to come at a high cost for a marginal benefit. We caution against approaches that would increase reliability by the smallest of fractions but impose large costs across energy users, who may not actually value reliability to this extent. Certainly, submissions to the ESB's recent consultation on the IRM expressed concerns that the tighter IRM could lead to increased costs for consumers for no real benefit.

The Brattle Group's report for the AEMC's Enhancement to the Reliability and Emergency Reserve Trader (RERT) rule change – a seeming pre-cursor to the IRM and Interim Reliability Reserve – found that in overseas jurisdictions "the reliability frameworks ultimately resulted in the system operator procuring more resources than system modelling shows is needed to meet the reliability standard" and argued that one possible explanation was that "system operators and policy-makers may have a bias towards delivering additional reliability, for example because these institutions do not themselves bear the costs of purchasing additional reserves".[2] We share these views and do not wish to see consumers saddled with extra costs to effectively 'gold-plate' the generation fleet.

That said, we can understand why there may be concerns about insufficient replacement capacity entering the market. While we see that the existing market settings – energy-only, high market price cap – are sufficient to signal that investment is needed, in reality a range of government interventions have created a situation where most new capacity in the market has been built as a result of an additional policy rather than pure market settings. The Renewable Energy Target has incentivised the construction of large volumes of renewable capacity while state-based renewable schemes are doing the same. The Queensland Gas Scheme incentivised the build of gas-fired generation in Queensland. As the owner of Snowy Hydro, the Federal Government will foot the bill for the construction of Snowy 2.0 and state governments have underwritten the construction of other generation facilities like diesel generators and grid-scale batteries in South Australia in response to the 2016 blackout. The history of state and federal investment in peaking capacity and these proposed new large-scale investments would make a rational investor cautious to invest in capacity themselves. This kind of government intervention can concentrate market power and risks creating an oversupply of capacity in a region. These impacts create significant risks and undermine the business case for private investment. Continued government investment in and operation of generation capacity will act as a barrier to private investment in the kinds of firm, flexible generation needed to complement the increasing volumes of variable renewable generation.

Given the high level of uncertainty around investment commitment decisions, action may be needed to ensure that replacement capacity does arrive in time as thermal plant closes and demand changes. The ESB has outlined that it will primarily investigate approaches linked to the Retailer Reliability Obligation (RRO) and the establishment of an operating reserve.

On the changes to the RRO, ERM Power does not support the proposal to create a stricter RRO. The structure of the Retailer Reliability Obligation with a trigger three years in advance of a potential reliability 'gap' followed by a confirmation one year in advance was extensively consulted on and came into place on 1 July 2019.

[2] Brattle Group, *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market*, February 2019, p. vi.

The purpose of the T-3 trigger was to provide the market with a signal that more capacity is needed and allow retailers the opportunity to close the gap by investing in supply or striking contracts. The T-3 arrangement also allowed for a particular time period to be flagged as being of most concern. For example, the 2020 ESOO has identified "weekdays in January and February 2024 for trading intervals that fall between 15:00 and 20:00" in NSW as the relevant trading intervals.[3] By signalling the timeframes well in advance, investments can be targeted to the best technologies or contracts can be struck with counterparties for these specific times or to reach demand response agreements. By removing the T-3 trigger, retailers will have fewer options to meet their contract position as it will be far more difficult to provide the necessary investment or strike bespoke contracts for specific trading intervals with little advance notice. It would also impose significant risks on retailers if a generator was to unexpectedly close in the one to three year window ahead of time, as it would be difficult and costly to secure sufficient contracts to manage the sudden change in circumstances, or to build replacement capacity in time.

ERM Power also considers that removing the T-3 trigger alone would require amendments to the RRO relating to the T-1 or T-3 trigger. We would argue that were the T-3 trigger to be removed then arrangements for the Market Liquidity Obligation and the contract position day would need to change in order to maintain the original intent of their use. The contract position day is currently set at one year before the start of the gap period. This would mean that a liable entity has around three months to finalise its contract book when a T-1 instrument is triggered before the contract position day, but that would follow a two-year 'warning' period due to the T-3 instrument, without which there is no warning. Retailers will either need to wear the carrying costs of hedge contracts for longer periods in anticipation of a potential T-1 trigger or attempt to contract in a short period of time before the contract position day.

In addition, the MLO was designed to assist retailers contracting following a T-3 instrument because while retailers must contract, generators are under no obligation to (Prohibiting Energy Market Misconduct Act notwithstanding). Without a T-3 trigger there is seemingly no legal requirement for the MLO to continue, leaving non vertically integrated retailers vulnerable. The ESB must consider how to ensure contract market liquidity can be maintained in the absence of a T-3 trigger.

ERM Power also rejects the concept of an RRO for physical contracts (as opposed to financial) if this applies to the entirety of a retailer's load. The concept of a physically-backed RRO was considered during the early stages of the RRO's development but would have the consequence of severely limiting liquidity in the contract market and imposing significant risks on smaller retailers. We strongly consider that the existing system which accepts financially-backed contracts as remaining fit-for-purpose. The current arrangements allow for the most commonly-used financial contracts, like caps and swaps, to be used to meet a retailer's RRO position and are typically, from a system-wide perspective, ultimately backed by a physical plant. Any approaches to enhance resource adequacy should not undermine contract market liquidity.

We also oppose the concept of shifting to a higher contracting level such as one-in-ten-year demand. This would drive an extraordinary level of over-contracting in the market which would inevitably lead to higher costs to consumers. We also see that requiring a change to contracting levels may also require consequential amendments to other aspects of the RRO.

For instance, while retailers have to present their contract position to the Australian Energy Regulator if a T-1 trigger is called, retailers' contract levels must be found to comply only if actual demand exceeds the one-in-two-year peak demand forecast. This aligns contracting levels with the compliance trigger. If the RRO was amended to require retailers to hold contracts for their share of one-in-ten-year peak demand, then logically the trigger point for compliance should also be if actual demand exceeds the one-in-ten-year peak demand forecast. Perversely, this would make compliance less likely to be assessed.

If the one-in-two-year trigger was maintained, but retailers needed to hold contracts equivalent to their share of one-in-ten-year peak demand then retailers would need to over-contract during the gap period to ensure

[3] AEMO, *2020 Electricity Statement of Opportunities*, August 2020, p. 60

compliance. This would incentivise generators to bid so as to be dispatched during these times, but it may not make any extra supply available. Rather, it would likely create a perverse outcome where contract market prices are high due to the extra demand, while spot market outcomes are low because generators have bid in such a way as to ensure they receive spot market revenue so they can meet their contracts.

ERM Power's analysis of the 2020 ESOO shows that one-in-ten-year peak demand forecasts is around 11 per cent higher than one-in-two-year peak demand forecasts in Victoria and South Australia, more than 8 per cent higher in NSW, and 3-4 per cent higher in Tasmania and Queensland. With Queensland and Tasmania not projected to have any issues with reliability over the next decade, this is not an issue. But for the other three states, this would likely see retailers having to increase contracting levels by 10 per cent or more (to account for a risk buffer).

As an alternative, ERM Power has developed two alternative in-market approaches which we consider would enhance the signals for replacement capacity, maintain the integrity of both the spot market and the contracts market, and result in lower overall costs.

Option A – Centralised tender for contracts for difference

Under this approach, AEMO, or an alternative central contracting body (CCB), would hold reverse auctions for contracts for difference for a volume of supply if the ESOO identifies a gap in a state more than 3 years out. The process should select the generation with the lowest cost and shortest tenure to minimise risks to consumers.

For instance, the 2020 ESOO identifies a gap of 154 MW in New South Wales to meet the Interim Reliability Measure in 2023-24, with higher volumes in subsequent years. The CCB would then hold a reverse auction to procure 154 MW of caps (or other product) from new capacity in NSW. This could be new build or upgrades to existing supply side resources or demand response initiatives.

The costs would be passed on to customers through a per MWh charge. In the event that the contract for difference resulted in a greater return for CCB than the costs, then consumers would see a refund in charges.

The advantage of this approach is that it provides certainty that additional capacity will be delivered for periods of critical need. The use of financial contracts like caps would mean that the provider would be heavily incentivised to be available to provide the contracted resource at times of high prices (generally peak periods) because if they failed to generate then they would have to pay money back to the CCB.

This model is also likely to be relatively low cost. Taking the example above of the gap in NSW in 2023-24, securing caps for 154 MW of supply or demand response capacity for one year would, at a cap price of $10/MW would cost around $13.5 million for one year.[4] During periods where prices are above $300/MWh (the usual strike price for cap contracts) the provider would have to pay money to the CCB. As such, the net cost to consumers would then fall. Crucially, this model also fundamentally supports the existing spot and contracts markets.

We understand that this approach would entail some risks. An auction approach could lead to investors waiting until a shortfall is declared in order to secure funds. However, the use of an auction process would likely limit this to some extent as a decision to provide new capacity in advance of an expected shortfall would then guarantee market revenue rather than risk missing out in an auction. There is also the inherent uncertainty of long-term forecasts meaning that too much capacity could be provided, with energy users footing the bill for some of this. Finally, there is a risk that the supply or demand response capacity may not provide capacity during times of high prices. However, as mentioned, this would result in funds being returned to energy users.

[4] This is based on the existing 30-minute settlement regime in the NEM. We expect these estimates would change under 5-minute settlement once that reform takes effect on 1 October 2021.

Option B – Certificate-based reliability gap

Our second approach involves a variation of the concept of the physically-backed RRO model (decentralised capacity market). In the event of a reliability gap identified through the ESOO, retailers would need to procure certificates based on their share of the gap at the time of peak demand but only for the capacity required to meet the gap. Similar to Option A, certificates would be allocated to new capacity only – i.e. new supply-side resources, upgrades to existing resources or new demand response.

Again, using the 154 MW gap in NSW in 2023-24, new or upgraded capacity could apply to AEMO to be certified as additional for 2023-24. Retailers would need to procure certificates equal to their share of load during peak demand. Assuming a retailer's load was 20% of the total at the time of system peak, that retailer would need to secure 30.8 MW of certificates for 2023-24.

This would retain the basic design principles of the RRO and create a transparent cost for additional capacity. As only the additional capacity required to solve the 'gap' would be paid for, this would limit costs.

Again, we recognise that this model does entail risks. Given the size of the 'gap' is unlikely to be significant, the market will probably be fairly illiquid, with the small gap split among existing retailers. It may also lead to monopoly power if just one provider is physically available to bridge the gap. Consequently, there may need to be rules around large existing generators making new capacity available to the market. Decisions would also need to be made around how long new or refurbished capacity would be eligible to create certificates for.

We encourage the ESB to consider the options alongside other approaches as part of the Resource Adequacy Mechanism workstream.

Ageing Thermal Generation Strategy

ERM Power considers that the ESB has correctly identified the risks associated with the transition away from thermal generation. However, we believe there are important contextual issues that the ESB has not adequately explored in the consultation paper. These relate to the timing of exit and the impacts of price rises.

ERM Power agrees that the impact of sudden exit of thermal plant, such as occurred after the closure of Hazelwood, is one that the market would not want to repeat. The impact on wholesale prices was dramatic and largely held until the recent economic slowdown related to COVID-19. What sets Hazelwood's closure apart from the current environment is that Hazelwood's closure was sudden, with only 5 months' notice given to the market. The Hazelwood closure also corresponded with the ramp up of output from the Queensland LNG facilities and a large increase in gas prices to gas-fired generation and a significant increase in the price of coal to power the coal fired generation in NSW which was required to increase production due to the loss of the very low cost Hazelwood. The current notice of closure rules that require 42 months' notice of a planned closure is a strong signal to the market of the need for more capacity, along with when and where. Combined with the existing market settings such as the Retailer Reliability Obligation, the Electricity Statement of Opportunities and the Integrated System Plan, investors have a wealth of information to make efficient investment decisions to replace exiting thermal generators.

On its own, the 42-month notice period does not provide sufficient investment certainty. In 2016, AGL announced its plan to close Liddell power station in 2023. Despite the 7-year notice, there have been highly politicised calls for AGL to reverse that decision or for another party to buy Liddell and keep it running. In September 2020 the Government went so far as to declare it would build gas-fired capacity if the market didn't "step up". The government intervention occurred despite a solid investment pipeline in NSW and several years remaining before forecasts show that any capacity is needed. The risk of government intervention that is unconstrained by market economics or commercial return requirements and concentrates ownership of capacity, raises the risk profile for investment decisions and will almost certainly inhibit the private sector's ability to reach threshold returns and robustness requirements needed to take final investment decisions to build capacity ahead of declared closures.

Further, the ESB expresses concerns about the possibility that higher wholesale prices in the aftermath of thermal plant closure will lead to remaining thermal generators “accruing economic rents, above long-run marginal costs”. While this may occur to some degree, the nature of an energy-only market like the NEM is such that generators may require periods of higher than normal prices in order to recoup long-run marginal costs over the entire life of the plant. The extent to which this is anything other than a short-term phenomenon depends on the level of competition in the market at the time as well as broader market issues such as water storage levels and gas prices.

The greater risk to replacement capacity that is relevant to investment decisions is that the existing plant decides to remain in the market longer than originally planned. New investment would be better supported by the notice of closure being an effective hard date for closure, with limited ability to extend this unless there was a delay in commissioning new plant or a reliability concern for the months following the closure date. If need be, rules could be adjusted so that AEMO could enter into a reserve contract with the plant for capacity to be available in reserve for a limited period following the closure date.

Essential System Services

As noted in the ESB’s consultation paper, ERM Power has made our position for system service markets clear through our submission to the AEMC’s System Services Rule Change. We recommend that the ESB consider our submission to those rule changes as a more comprehensive response to issues relating to this Market Design Initiative. Though, we advise the ESB that our proposed Power System Security Ancillary Services (PSSAS) concept is designed to be a market-based model for the most part rather than structured procurement. We consider that markets could be used for inertia, reactive power, fast frequency response, and system strength.

ERM Power considers that, where possible, a market-based approach is the optimal choice for the provision of essential system services. Under our proposed PSSAS model, generators and other non-regulated providers would bid for the provision of different system service in much the same way as they do for the existing energy market and ancillary services markets. AEMO would then co-optimise bids across the energy market, ancillary service markets and PSSAS market to find the lowest cost solution for the provision of all services. A key strength of ERM’s PSSAS model is its flexibility to efficiently managed unplanned system events by facilitating the rescheduling of plant to respond to real time market conditions. Other proposed solutions could require AEMO to schedule services on an N-1 basis to manage such unplanned system events resulting in increased costs to consumers.

Operating Reserve Market

The development of an operating reserve market is one that we consider must be considered alongside the Resource Adequacy Mechanism and Thermal Generation Exit Strategy Market Design Initiatives rather than independently from these. While the use of an operating reserve market may provide a financial incentive for dispatchable plant to remain ready for dispatch and able to ramp up as needed, this is already efficiently managed by the FCAS market via the provision of spinning and quick starting reserves. We acknowledge that an operating market could help to provide support for the power system if sudden unexpected changes in supply occur due to loss of a large generating unit or transmission infrastructure, uncertainty in variable renewable energy output, or unexpected changes in demand were to occur, leading to sudden changes in system frequency. However as noted, this can be managed via existing FCAS markets.

It could also be argued that an operating reserve market would allow the market operator to look ahead in some time frame to determine whether certain generators, who though their bids have indicated an intention to self decommit or not self commit, may be needed to keep dispatching energy in the market in order to provide these additional reserves and power system services. However, we believe such concerns are better dealt with via ERM Power’s proposed PSSAS market and improvements to AEMO’s pre-dispatch forecasts including an extension of the 5-minute pre-dispatch period to 3 to 4 hours. The fact that these services are interrelated demonstrates the importance of forming a cohesive response with other essential system services to recognise the linkages and interactions between different approaches.

ERM Power struggles to see how an operating reserve market would improve on the current information provisions or settings in the market. The existing information provision and market settings, including the high market price cap, the short-term projected assessment of system adequacy (STPASA) and pre-dispatch PASA (PDPASA) along with AEMO's declaration of lack or reserve (LOR) notifications, which includes flexibility for forecasting uncertainty, all of which provide signals in different time frames of up to seven days in advance for capacity to be made available to the market. We have observed that generators and demand response providers do respond to indicators of tight supply-demand balance and make themselves available. As a last resort AEMO has the ability to intervene in the market to secure sufficient reserves via the use of a Clause 4.8.9 Direction or procurement of out of market reserves via the Reliability and Emergency Reserve Trader.

While we agree that changes in potential demand outcomes and variable renewable generation output will become increasing challenging in the future, it needs to be understood that the current AEMO forecasts contained in the STPASA and pre-dispatch already include for such variations and the process for the declaration of LOR conditions also contains an additional forecasting uncertainty measure value which increases in value over future time periods. Though we agree that the value of generation associated with a credible contingency event may also change over time, the current design of the FCAS markets allows for variable procurement volume of FCAS reserves by AEMO to manage this risk. We are of the view that the variability factors are already well catered for in the market's short-term forecasting framework.

The current market design allows for decision making in the form of self-commitment and self-decommitment by the respective market participants. This market design feature ensures that economic risks associated with these decisions are borne by the market participant as opposed to a central commitment and decommitment market design where the risks of decisions made by the market operator are borne by consumers. Market participants have the ability to manage these risks through the financial contract markets where a generator receives a fixed price for the negotiated contract volume, regardless of spot market dispatch outcomes. An operating reserve market would in our view result in a transfer of the economic risks with regards to such decisions onto consumers.

It is unclear in ERM Power's view, what an operating reserve is then seeking to achieve or how generators would respond. In essence, it appears to be an additional selective payment for some generators, or demand response providers, who are not bid as available or to become available, even though experience shows they tend to make themselves available when needed based on the existing market economic signals. ERM Power wonders how this may play out in practice – could generators actually remain unavailable for longer than they otherwise would to try to extract a higher price in the reserves market? Would generators seek to reserve some capacity for the reserves market instead of bidding this capacity for normal dispatch. Could this lead to lower volumes of contracts being made available, and therefore inadvertently push wholesale, and retail prices higher? It would seem to create a kind of limbo capacity market that is neither in-market through the usual processes nor out of the market (and in-RERT).

Also, as an operating reserves would presumably be withheld from the normal dispatch process until deemed required by AEMO, we are concerned that at times of tighter, but not necessarily tight supply demand balance, the normal dispatch prices for energy could be artificially inflated by the need to retain these in-market reserves, resulting in higher costs to consumers.

Fast Frequency response

ERM Power sees there is strong merit in implementing the proposed fast frequency response (very fast contingency FCAS) markets. While there is no urgent need for these markets now, the time it takes to design, implement and integrate these markets with the existing (and potentially changing) market ancillary services markets means that we consider there would be benefits to doing this now rather than waiting until it is past due.

This would also provide participants with time to adapt their own systems and adjust strategies to participate. Very fast contingency FCAS could become an extremely useful tool in the future to help manage frequency deviations as the quantum of synchronous generation decreases resulting in a decrease in synchronous (real) inertia and a continued increase in the volume of inverter-based generation and load in the power system.

We believe a simple amendment to the design of the existing Market Ancillary Services as set out in Clause 3.11.2 to include the *very fast raise service* and the *very fast lower service* and inclusion of defined terms for these services in Chapter 10 of the Rules. AEMO would consult on and amend the M*arket Ancillary Services Specification* to specify service provision requirements for these new market ancillary services following amendments to the rules. Cost recovery and settlement, and provisions in the Rules associated with the cumulative price threshold, the market price cap, market suspension, etc. for these new ancillary services would mirror that applied in the Rules to the existing fast, slow and delayed market ancillary services.

AEMO would monitor and provide updated forecasts to the market regarding the commencement of procurement of these new very fast contingency FCAS.

Scheduling and ahead mechanisms

ERM Power appreciates the work the ESB has undertaken to refine the scheduling and ahead markets options since the release of a consultation paper on ahead markets in April 2020. At the time ERM Power provided qualified support for the Unit Commitment for Security (UCS) model on the grounds that this would bring vastly more transparency than AEMO's existing directions process. We also added that where possible the services identified as needed ahead of time should be delivered using a market-based approach rather than relying purely on generators providing their cost information to AEMO and that any "aheadness" should be based on the shortest notification timeframe possible. We remain committed to this approach.

As such, the UCS + ahead markets model would appear to be a sensible approach provided that participation in the ahead market component remains voluntary. This is effectively the system we proposed as part of our PSSAS model for essential system services. We consider that the ahead markets and system services Market Design Initiatives are intertwined to such a degree that they need to be considered in a single response.

As highlighted in our submission to the AEMC's System Services rule change, we envisage that AEMO would need to use some degree of "aheadness" in order to make the decision that certain resources are required at by a certain time. This should be as late as possible to ensure it is needed while also allowing enough time for the participant to make the service available. Different resources will have different lead times, so in this sense, several windows may need to be used – for example, some services could require a dispatch instruction to be committed for dispatch 3 hours ahead, while an additional service could be required to be provided with just 30 minutes notice to restore the power system to a secure operating state following an unplanned system event. ERM Power also recommends that this be co-optimised with the energy and ancillary services markets.

We also are broadly supportive of the concept of a voluntary ahead market for the provision of these services. This is chiefly because some of these services will need to be committed ahead of time, so it does make sense to offer providers the opportunity to provide offers to make those available ahead of time. However, this support is contingent on the fact that the ahead market should remain voluntary for all participants.

We also consider that, to the extent that an ahead market will be a financial commitment as opposed to a physical commitment, then it will be important for the right entity to be responsible for operating that ahead market.

Two-sided markets and integrating DER

ERM Power considers that a more active demand side could help to deliver a more efficient market overall with a closer alignment of demand and supply bids. We caution that this must be done in a way that leads to genuine benefits rather than one which adds risk across the market. The ESB's proposed, staged approach based on voluntary participation goes some way towards achieving this.

Given the links between distributed energy resources (DER) and two-sided markets, we consider it reasonable for the ESB to combine these two workstreams, or at the very least, focus on how DER can be incentivised to participate in two-sided markets. As such, our comments on both the two-sided markets and DER MDIs are combined.

As a first comment, ERM Power does not view a two-sided market as a pre-requisite for improving DER integration within the market as a whole. There may be low-cost ways to better incentivise DER to operate in a way that provides broader benefits to the market and does not act as a barrier to investment in DER. The AEMC's consideration of rule changes from SA Power Networks, the Australian Council of Social Services and Total Environment Centre, and St Vincent de Paul is a solid example of this.

ERM Power expressed reservations about the more drastic changes discussed in the ESB's previous consultation on two-sided markets in May 2020. We argued that a voluntary approach could work provided that there were improved incentives for participation. We noted that technically the NEM was already a two-sided market in that load could choose to be scheduled but, with a handful of exceptions, most loads chose not to be as there is no advantage to doing so. We note that customers can already choose to be exposed to the spot price and manage their load accordingly. Some customers choose to take on the spot price with their retailer which gives them the same pricing as a scheduled load without any of the obligations around bidding and compliance. It is therefore easy to see why the demand side would choose not to take part in a two-sided market of this kind.

As such, we see merit in the ESB's proposed approach to promote options for consumer engagement and look to expand those opportunities in years to come. There could certainly be benefits in finding ways to encourage consumers to use more at times of low prices and use less at times of high prices. Similarly, consumers with solar PV could be encouraged to switch off their systems at times of negative pricing (subject to system security concerns). Of course, mandated feed-in tariffs distort these decisions, as consumers receive a fixed price for all solar PV exported rather than one closely linked to the spot price. The AEMC's decision on the DER integration rule change could help change these incentives and provide improved signals for better integrating DER, though this would largely apply to solar PV and battery storage.

Demand response as a separate form of DER has its own challenges. The wholesale demand response mechanism (WDRM) will be in place from October 2021 and this will provide a market for demand response from this time subject to the load meeting the requirements such as metering and baselining that AEMO is in the process of developing. We are aware that some parties believe that the WDRM does not go far enough as it does not include small consumers and that large load participation will be subject to whether a load can have an accurate baseline. We also understand that there are limitations on the ability of some commercial and industrial users to safely provide demand response within the 5-minute settlement timeframe once the 5-minute settlement rule change enters into force on 1 October 2021. Of course, demand response is not required to participate in the WDRM and can enter into arrangements with their existing retailer or separately metered arrangements with intermediaries or third-party retailers.

The challenge for any demand response is determining what would have happened but didn't (the baseline). The more volatile the load, the harder it is to determine a baseline. There are also a vast number of commercial and industrial users who do not wish to actively respond to price signals and instead wish to operate as they normally would. It is crucial that these users can continue to operate as they do now without needing to continually monitor the wholesale electricity price or their load. This is one of the key reasons that retailers exist – to manage the price and volume risk in the wholesale market so that users can focus on their key business.

We acknowledge that there are some loads that may operate sporadically but can respond to price signals be readily controlled such as electric hot water, pool pumps, air conditioners and potentially battery storage and electric vehicles. There could certainly be benefits to creating incentives for these kinds of loads to be switched on at times of negative or low prices and off during high price periods. This could be done by an individual consumer or remotely via a consumer's retailer or potentially a third-party. This would be a worthwhile consideration for the ESB.

In the near-term, ERM Power considers that any work on two-sided markets should focus on the existing WDRM and Demand Side Participation Information Portal as well as progressing the AEMC's work on rule changes from SA Power Networks, the Australian Council of Social Services and Total Environment Centre, and St Vincent de Paul relating to DER integration. ERM Power made a submission to the AEMC on these rule changes and believes that there is significant overlap with the broader aims of both the two-sided market and DER MDIs.

Coordination of Generation and Transmission Infrastructure

ERM Power has engaged regularly with the AEMC and others on the Coordination of Generation and Transmission Infrastructure (COGATI) reforms. We will provide a separate submission on COGATI to the AEMC as part of their separate consultation.

On the question of the cost-benefit analysis from NERA Consulting, we have concerns with the modelling undertaken as it does not reflect commercial reality; the circumstances of any dispatch efficiency gains are likely to be limited, and the overall benefits appear severely overestimated. There is an overestimation of a wealth transfer due to the lack of proper consideration to the implementation of Renewable Energy Zones (REZ), including the transmission investment in shared network capacity that will be undertaken to support REZ as well as the up to date information on Integrated System Plan (ISP) projects. The cost-benefit analysis undertaken by NERA only included specific ISP projects – Group 1 and Group 2 projects from the Draft 2020 ISP and did not include any REZ network extensions indicated in the Final 2020 ISP report or network augmentation projects listed in the network service providers annual transmission planning reports. There also appears to be a lack of transparency as to whether the jurisdictional transmission reliability standards for reliable supply to consumers has been met in the reform case, given the use of AEMO's Draft ISP project plan only without inclusion of the necessary supplementary transmission investment required to support these network augmentations.

The modelling ignores the impact to the contract market – with the need to purchase financial transmission rights (FTR) to manage the additional risk. The modelling fails to include for the costs of FTR purchases and the impact of this on contract prices. We disagree with NERA's assumptions around contract liquidity and believe there is a significant concern about impacts of the reform to market liquidity of scheduled generation receiving the locational marginal price (LMP). The reforms may result in generators selling energy at the generator's gate (local connection node), rather than the regional reference node, transferring risks to retailers or large end use customers who may not be able to properly manage the risk with securing FTRs. The reforms will also impact exchange of futures for physicals (EFP) contract liquidity as a means for managing credit risk.

NERA's analysis also appears to significantly understate the challenges around transition – particularly with regard to the legal costs of recontracting and likely reopening of wholesale contracts and power purchase agreements (PPA). NERA's costing for contract re-negotiation assumes that each side would like to honour the original terms of the agreement in spirit. In reality, when a contract has been signed at a historic price and underlying prices have moved, one side will be strongly incentivised to mount a legal case for a contract break.

There are several risks of the proposed reforms that may impact negatively on many participants in the market and ultimately consumers. The reform creates significant risks and investment uncertainty resulting in disruption to existing long-term energy contracts and added costs for market participants due to the Locational Marginal Pricing regime being proposed.

We are concerned the reform no longer attempts to address the key question posed by the COAG Energy Council of improved coordination of generation and transmission investment. Despite the key original justification for the reform, the proposed reform is instead aimed at modifying scheduled participants access to the regional reference price for settlement. To date, the arguments provided by the AEMC to support the changes in addressing the coordination of generator and transmission investment appear unclear and the analysis does not comprehensively explore the implications to participants and consumers from both a physical spot market and financial contracts market perspective.

We consider there is a lack of evidence to support the AEMC's view that FTRs themselves will drive transmission investment or have a positive impact on locational signals for both generation and load in the Australian market. The AEMC has failed to identify any overseas electricity market in which FTRs are used as the basis for transmission investment. Whilst some overseas markets do use FTRs, overall this reflects only a minority of overseas electricity markets.

Transmission investment is now being considered outside the COGATI reforms, by other market, government and regulatory initiatives, such as Renewable Energy Zones, actioning AEMO's recommended ISP projects and the transmission network service providers normal Annual Transmission Planning Report and RIT-T process for projects to connect AEMO's ISP projects to the customer load centres. Locational information is also being further supported by the Transparency of new projects rule.