18 May 2018

Sarah-Jane Derby
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Ms Derby

RE: Reliability Frameworks Review – Direction Paper (EPR 0060)

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy market Commission's (AEMC) Reliability Frameworks Review's (the Review) Directions Paper.

About ERM Power

ERM Power is an Australian energy company operating electricity sales, generation and energy solutions businesses. The Company has grown to become the second largest electricity provider to commercial businesses and industrials in Australia by load[1], with operations in every state and the Australian Capital Territory. A growing range of energy solutions products and services are being delivered, including lighting and energy efficiency software and data analytics, to the Company's existing and new customer base. ERM Power also sells electricity in several markets in the United States. The Company operates 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland. www.ermpower.com.au

General Comments

ERM Power thanks the AEMC for their comprehensive Directions Paper which builds on the previous stages of the Review and can complement previous and ongoing workstreams such as the development of the National Energy Guarantee (NEG). The Review can provide an avenue to examine the various options that could be considered as the NEM evolves.

Our submission to the interim report provided our views on forecasting, demand response, day ahead markets and strategic reserves. As noted by the AEMC, the Australian Energy Market Operator has submitted two rule changes relating to the Reliability and Emergency Reserve Trader (RERT) arrangements. We intend therefore intend to make our comments on strategic reserves thorough these two rule change processes as well as through any consultation on the NEG given the interaction between the RERT and the procurer of last resort mechanism described as part of the high-level NEG design.

This submission sets out our views on forecasting, demand response and day ahead markets as discussed in the Direction Paper.

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

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

Yours sincerely,

[signed]

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Forecasting

Future demand forecasts of reasonable accuracy are one of the two central pillars of any assessment of future supply reliability. As discussed in the Directions Paper, AEMO's current long-, medium- and short-term forecasts all demonstrate a consistent over-forecasting of demand in all regions with a particular emphasis during the potentially higher demand summer period. Although we agree with the AEMC that AEMO's forecasts have not worsened in accuracy over time, they do not appear to have materially improved either. The fact that forecasts have consistently been too high suggests there is an underlying conservatism or bias towards overestimating demand.

It should be noted that this is not the first time this conservative bias has been highlighted by the industry to the Commission, in 2010 during the Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events; the National Generators Forum (NGF) raised the same forecasting conservatism concerns. In their submission, the NGF questioned the weight placed on the forecasts to determine future low reserve conditions and was of the opinion that the forecasts were not robust enough to justify market intervention, in particular as it relates to the Reliability and Emergency Reserve Trader.[2] We believe the concerns raised with regards to the conservative bias in the market operator's forecasts in the NGF submission in 2010 remain relevant for this current review.

The design of the National Energy Guarantee's Reliability Guarantee appears to place added emphasis on AEMO's forecasts with the prospect of unserved energy leading to the trigger of the reliability guarantee, placing requirements on retailers. Thus if the NEG is implemented, the accuracy of AEMO's forecasts, particularly the longer-term forecasts, will be critical to guiding investment and hedging strategies. They will have the potential to fundamentally shift a retailer's future investment strategies and change costs for end-use consumers. Therefore we consider that it is critical for AEMO's forecasts, and the methodologies underpinning them, to be as transparent and rigorous as possible. Our comments in this section are made in this light.

While the Energy Security Board's High Level Design of the NEG flagged that AEMO should be required to consult with stakeholders on forecasts and seek input from the AEMC's Reliability Panel this is similar to the recommendations in the Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events Final Report in 2010. As indicated earlier in this submission, despite the recommendations made in 2010 the accuracy of AEMO's forecasts have failed to materially improve.

We believe this change alone may not deliver the rigor and transparency required and fails to provide sufficient independence and review of AEMO's process. We suggest the following changes to the future long, medium and short term demand forecasting process:

1. A rule change to require the Reliability Panel to consult on and develop a demand forecasting methodology guideline, with a recommendation to commence the process with an open workshop, as opposed to an Issues Paper.
2. A rule change to require AEMO to prepare and consult on a process description to meet the guideline

[2] NGF Submission Page 14 – AEMC Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

3. A rule change to require the Australian Energy Regulator (AER) to issue an annual review of AEMO's forecasting process to determine if the process description was followed.

Whilst this may appear to be a significant change in the forecasting process, ERM Power believes this level of change is warranted to ensure that the accuracy of forecasts are improved to a sufficient level to minimise the potential for conservative bias which will result in additional costs to consumers whilst at the same time ensuring the Reliability Standard is continued to be met.

ERM Power is also concerned that the current MT PASA requirements as set out in the Rules were formulated to support the original deterministic forecasting process and may no longer be fit for purpose for the revised probabilistic process due to commence on 15 May 2018. We contend that improvements can be made to the MT PASA forecasts that would increase transparency and improve the accuracy of unserved energy (USE) and Loss of Load probability forecasts. These include publishing individual unit availability data available through MT PASA. We believe that this would improve transparency and overall efficiency by giving all participants a clearer picture of generation capability and thus allowing all generators, especially smaller, non-vertically integrated generators and retailers and large energy consumers to plan for expected events in the system.

AEMO could better serve the market and more accurately calculate the potential for USE by providing a greater range of forecasts rather than solely the P50 and P10 outcomes. Currently the use of only P10 and P50 forecasts in the MT PASA USE calculation with a combined USE probability weighting of 100 per cent results in an additional conservative bias above that already imposed by the conservative nature of the regional demand forecasts.

We believe that AEMO should provide and utilise in the MT PASA process a more comprehensive range of forecasts including P10, P30, P50, P70 and P90 demand outcomes with each forecast assigned an identical probability weighting of 20 per cent with regards to the potential USE calculation. This would improve the accuracy of the potential USE calculation and give market participants and other interested parties improved visibility of the range of potential outcomes in the market, particularly as it can be influenced by weather conditions. In assessing the Loss of Load Probability, the process should also allow for support via interconnectors from adjacent regions and not limit supply outcomes to only that located within a region.

It is also worth noting that the daily maximum demand forecasts as contained in the MT PASA are static in nature, usually only updated each year following the issue of the National Electricity Forecasting Report or occasionally following an update to this report. We believe the MT PASA process would benefit from the use of progressive Bureau of Meteorology monthly updates in the 3 month time horizon such that forecast in this timeframe are dynamic and more representative of the current forecast of weather conditions.

Additionally, and as set out in ERM Power's response to the AEMC's Interim Report, we consider that there is a need for greater reporting obligations on AEMO's forecasts at all timescales. The National Electricity Rules (the Rules) - Clause 3.13.3 currently sets out fairly basic requirements with regards to the accuracy of AEMO's demand forecasts as issued in the Statement of Opportunities. Yet there is no equivalent obligation that applies to AEMO's ST and MT PASA reports. These reporting obligations should include reference to historical and actual temperature outcomes and require that forecasts and real time data be provided to participants in a matching format to allow independent verification of outcomes.

We therefore agree with the Commission's comments that there could be benefits for market participants and AEMO if there were greater reporting on the differences between forecast and actual outcomes, especially in relation to the 30-minute pre-dispatch, STPASA and MTPASA forecasts.

ERM Power believes this would be best served by a rule change to require the AER to prepare and issue quarterly reports of actual demand vs forecast outcomes in the Pre-Dispatch, ST and MT PASA timeframes.

Retailer forecasting obligation

The Commission has asked for comments on the potential for a retailer forecasting obligation to be introduced in order to assist with reliability "through better integrating distributed energy resources with the wholesale market" and give retailers improved incentives "to monitor and control… the load of their customers". ERM Power does not agree that requiring retailers to provide formal demand-side forecasts would lead to the kinds of benefits the AEMC highlights in a cost-effective and efficient manner.

While retailers do generate their own forecasts of customer load, these forecasts are not used to provide an accurate picture of customer load. Instead, this forms part of a retailer's risk management strategy, as an input to indicate how they should contract to an efficient level. There is also potential for over forecasting of overall demand to occur as peak demand for all retailers will not occur in the same Trading Interval. We believe AEMO is in a far better position to provide forecasts of overall consumer demand given the totality of information available to them. That is not to say that the information to which they have access is complete or that their forecasts cannot be improved. For instance, based on our understanding of their current forecasting activity, we believe that AEMO could better take into account the impacts of temperature on consumer demand.

Customers are also able to contract with third-parties to provide demand response. This occurs without a retailer's knowledge. This means that a retailer will not fully understand how a customer will respond to high prices or what the demand-side trigger is with the third party. A formal retailer forecasting obligation could potentially penalise retailers whose customers have chosen to enter into demand response arrangements outside the bilateral retailer-customer dynamic.

It is also worth noting that Retailers are now providing AEMO with improved data on demand response through the Demand Side Participation Information Guidelines. This will provide AEMO with increased transparency of the potential impact of demand response at times of high prices.

We consider that time should be allowed to assess the impact of these new demand response reporting requirements to determine whether this will provide improved detail about demand response before imposing costly and difficult obligations on retailers to effectively provide demand-side bids into the NEM.

Solar and wind self-forecasting

The Commission also raises the prospect of creating a self-forecasting obligation for solar and wind generators. Wind and solar generators have real-time data on localised weather conditions and current plant performance available to them which allows them to develop up-to-date forecasts of expected generation. They therefore have the ability to provide more accurate assessments of expected generation levels than relying on AEMO's Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). Our understanding is that these market participants want to provide this information to AEMO and if so, should be allowed and indeed encouraged to do so.

Such that this self-forecasting becomes a requirement in the rules, care must be taken to ensure that this is targeted at generators of an appropriate size and does not impose unnecessary and inefficient costs on generators. ERM Power considers that as a starting point it could be appropriate to require generators greater than 30 MW of registered capacity to provide self-forecasts while generators between 5 and 30 MW could provide self-forecasts on either an opt-in or opt-out basis. This would allow smaller generators who see benefits in providing self-forecasts to do so without imposing potentially significant costs on other smaller wind and solar generators who may be unable to provide self-forecasts.

Day ahead markets

As set out in the Directions Paper the energy-only NEM has a large number of significant "time ahead" information provision obligations on participants which provides the market operator with a high level of information on future availability comparable to the day ahead market designs as covered by the review or offered by way of example to date. In turn, AEMO publishes this information plus their own forecasts of system demand and supply reliability over the pre-dispatch and short- to medium-term time horizons.

In addition, although a centrally co-ordinated day ahead trading platform may not currently exist, there is nothing in the NEM design that prevents day ahead or even "on day" trading of hedge contracts between counterparties should the need exist. This is further supported by the rebidding provision, clause 3.8.22 of the Rules which facilitates the adjustment of bids for changes in contract position following the 12:30 day ahead bidding submission closure. It is doubtful that a day ahead market would have the ability to support "on day" trading due to its design requiring generators to lodge a firm day-ahead schedule.

It is currently unclear how a day ahead market would improve upon the current information obligations and the ability for participants to freely engage in hedge contract trading, or in what way it would provide further incentives to promote power system reliability.

As noted by the AEMC, there are a range of potential designs for day ahead markets, with each one leading to different outcomes and promoting different responses from market participants all of which may not lead to positive benefits compared to the existing market design. It is therefore difficult to comment on the benefits of day ahead markets without having a specific model to examine. Nonetheless, we observe that the introduction of a day ahead market into the NEM would not be a simple case of adding it into the existing market structure. Around the world, day ahead markets are used in conjunction with balancing markets. This would suggest that the NEM would need to be redesigned to amend the current energy only gross pool market to act as a balancing market as well. This would represent a substantial shift away from the current market design and one that would require greater consideration than simply whether or not to introduce a day ahead market. It is worth noting that in balancing markets, the supply side is in effect paid to reduce as well as supply additional energy to consumers.

Similarly, as an energy-only gross pool market with a high market price cap, the NEM is designed to incentivise peaking plant to remain available even though they may only be used for several hours each year. The high market price cap also drives the financial cap market which is used by buyers of energy to hedge against price spikes and incentivises sellers of cap contracts to be available to generate when prices are high. The introduction of a day ahead market could dampen these necessary price signals potentially leading to lower levels of availability or less future investment in flexible peaking plant. Ultimately this could lead to higher costs for consumers, increased risks to reliability and an increase in the level of costly market interventions.

The AEMC has identified three potential objectives for day ahead markets:

1. To provide market participants (both demand and supply side) with more, or better quality, information so that they can incorporate this information into their unit commitment or demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.
2. To provide the system operator with more, or better quality, information so that the system operator can use this information to more efficiently manage the system in relation to reliability and security outcomes, while maintaining the current generator self-commitment arrangements.
3. To provide the system operator (rather than participants) with a schedule that centrally coordinates unit commitment decisions, the intent being to increase the operational efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

While ERM Power agrees that specific types of day ahead markets could indeed achieve these objectives, we do not see that it is only day ahead markets that can achieve this. Indeed, the existing structure and features of the NEM already achieves these objectives.

The projected assessment of system adequacy (PASA) processes provide both supply and demand side market participants with significant information which is used to factor into their decisions with regards to unit commitment and de-commitment, settings for bids and offers and demand side response (objective 1).

There are also a number of current market features that provide information to the system operator to allow it to maintain system reliability and security such as:

- unit commitment and de-commitment
- availability in the various ancillary services markets
- the potential for the need for market intervention
- the requirement for security constraints it is currently employing in dispatch of synchronous generation to facilitate higher levels of intermittent asynchronous generation output in South Australia (objective 2).

The Pre-Dispatch and day ahead bid lodgement process provides both day ahead pricing signals and dispatch outcomes to participants and AEMO (objectives 1 and 2).

The rebidding provisions promotes the ability for generation dispatch to be amended closer to real time where more overall economically efficient outcomes can be achieved relative to current costs and contracting position (objective 3).

Some may argue that objective 3 may be better managed by central co-ordination of dispatch by the market operator as opposed to the existing market structure. However, the NEM was built upon the idea that the “market” will dispatch more efficiently than a centrally-coordinated market. To shift away from this would represent a change of extreme magnitude for the NEM. This change would also require participants to provide the market operator with large amounts of regularly updated "commercial in confidence" information to allow the market operator to attempt to optimise operational dispatch outcomes. This in itself would be an onerous task on participants, which due to its limited focus on operational outcomes, may not lead to the optimum efficiency outcomes overall when other factors such as future investment and generation closures are considered.

Indeed it would not be the same market and would require a vast number of complementary changes, including in the financial contracts markets, to ensure that participants have the same incentives to be available and facilitate trading of hedge contracts to the same quantity levels as they do now. This is therefore a decision that must not be taken lightly. The common link between these three objectives is improved information provision for the system operator and market participants. If that is the ultimate aim then alternative options should also be considered rather than focussing on day ahead markets. It may be that adjustments to existing market features could lead to similar or more optimal outcomes at far lower costs without overhauling the current NEM.

We also believe careful consideration needs to be given with regards to the potential impact of such a change in market design on the operation of intermittent generation sources. Whilst day ahead forecasts of output can be made to meet the day ahead scheduling obligations, there will remain a level of difference between forecast and actual outcomes. Whilst intermittent generation firming products are starting to emerge in the hedging contracts market, it is uncertain that this product could continue to be available under an alternative market design.

Finally, given the development of the exact design of the National Energy Guarantee is ongoing, and it is likely to be the main policy driver for the electricity sector over the long term, we consider that it would be prudent to await the implementation of the Guarantee before deciding on major changes to market design arrangements such as a day ahead market.

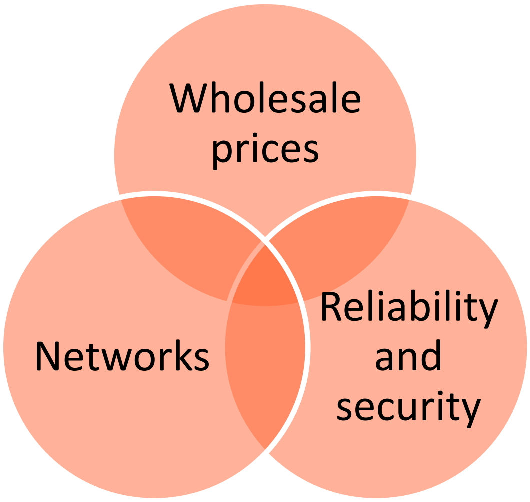
Demand response

The AEMC proposes several potential options for how to increase the levels of demand response in the system.

We believe that at the first instance it is important to consider the various drivers for demand response. We have identified three major reasons for demand response to occur:

1. To reduce exposure to high wholesale prices
2. To reduce the impact on local networks and ultimately defer network investment in augmentation
3. To assist in maintaining system reliability

We believe this can helpfully be presented in the graphical format below:



As can be seen, these drivers may overlap at times, with a single demand response event providing multiple services. Yet different parties will benefit from each and may want to be able to call on demand response at different times to achieve their aims. ERM Power believes that this often gets lost in discussions on demand response in the NEM. We discuss each of these drivers in turn.

In the case of a retailer, reducing demand may reduce exposure to high wholesale prices but this is not always the case. A retailer which has undertaken a prudent hedging strategy may have sufficiently mitigated the financial risk of high wholesale prices and as such would see no benefit from reducing demand. Similarly, a user who faces a fixed energy cost regardless of price outcomes in the wholesale market is not exposed to the risks of high wholesale prices. As such, neither party would see benefit from reducing their demand.

A network business may wish to reduce demand in certain areas to avoid the costs of augmentation or avoid localised blackouts. These instances of local network peak demand may not align with high wholesale prices. As such neither a retailer nor third-party aggregator would have any incentive to dispatch, or knowledge of the need, for demand response to assist the network unless the network business had contracted directly with the retailer or third-party aggregator to supply such a response when requested to do so.

Finally, demand response can help keep the system reliable and secure by lowering demand to ensure there is sufficient reserve capacity available, to assist with management of major transmission paths line loadings or to respond to changes in system frequency following events such as a generator or interconnector tripping. AEMO dispatched relatively small amounts of demand response (approximately 40 MW on average) for system reliability purposes twice over the 2017-18 summer as part of the RERT at significant cost to consumers. Again, while it may be expected that at times of low system reliability there would be high wholesale market prices this was not always the case in the 2017-18 summer. As such, although there may have been additional demand response available at short notice and willing to participate, it is unable to participate as part of the RERT because it is classified as on-market.

Consequently, we consider that there is a need to optimise the use of demand response to ensure that it is available for all of the above purposes but not displacing one use over another. Obviously this would also need to ensure that the party providing the demand response is only compensated for responses that are genuinely additional. One such way to achieve this could be to allow retailers and third party aggregators with demand response the opportunity to on-sell their demand response to AEMO as part of the RERT. This may be particularly effective in the Short Notice RERT timeframe. This would provide AEMO with an option to quickly and efficiently access additional demand response at lower costs than typical RERT contracts. In situations where the retailer or third party is not dispatching, or intending to dispatch the demand response, AEMO could dispatch this for the RERT. We submit this would be a good first step to efficiently unlock additional demand response prior to the 2018-19 summer period.

Development of a mechanism to increase demand response

The Australian Government has accepted 49 of the Finkel Review's 50 recommendations, including recommendation 6.7 which directs the AEMC to "*undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market… [and to] include a draft rule change proposal for consideration by the COAG Energy Council*."

We agree with the Commission's view as discussed in the Directions Paper that there may be greater barriers to facilitating additional demand response than simply the distribution of financial benefits and the technical aspects of consumers providing demand response. We point to the widespread opposition, both by consumers and governments to a simple demand response signal in the form of Time of Use tariffs as an example of this. Notwithstanding, we fully support the further investigation of avenues to incentivise additional demand side participation.

The AEMC's Directions Paper has identified three potential options for increasing the level of demand response in the NEM:

1. Transferring the value of the wholesale demand response from the existing FRMP to the aggregator.
2. Transferring spot market responsibility for demand responsive load from the existing FRMP to an aggregator.
3. Providing additional incentives for retailers to offer demand response products.

We believe that option 1 has already been exhaustively examined and discussed via the Demand Response Mechanism that the AEMC finalised in early 2016. Little has changed since that time to suggest that the significant problems with that proposal, such as how to accurately develop baselines, have been resolved. As such, we do not recommend that the AEMC pursue this model again.

There may be merits in exploring the Singaporean model discussed in the Direction Paper, which we see as being a modified version of the AEMC's Option 1. This would however represent a significant shift in the current market design which would need to accommodate more demand-side bidding and would also require an uplift payment levied on all loads to provide the incentive payment to the demand response provider. This model has the benefit of only rewarding aggregators or price responsive load when demand response is actually delivered, this may be at odds with views expressed in a number of submissions regarding the need for facility or availability payments to facilitate additional demand response.

Option 2 proposes a potential solution to the distribution of financial benefits for the provision of demand response. ERM Power supports further consideration of this option where two financially responsible market participants (FRMP) could be allocated to a connection point on the proviso that;

1. the price responsive load can be separately metered, and

2. the second FRMP is responsible for all energy supplied to or consumed at the price responsive load metering point for all settlement periods.

We would not support a proposal that the second FRMP is only responsible for the energy supplied to or consumed at the price responsive load metering point during periods where demand response is active. Such an arrangement would create added challenges on retailers in hedging load, settlement and managing obligations such as the potential reliability obligation under the NEG. This kind of arrangement was examined and rejected by the AEMC in its assessment of the Multiple Trading Relationships rule change. That rule change was rejected on the grounds that customers can already engage multiple retailers at the one site and that making the change would likely increase costs for all customers for little wider benefit.

Option 3 considers the option of developing a special fund, funded by a levy on all retailers and therefore potentially consumers, to facilitate additional demand response in the NEM. This Fund would reward retailers for implementing demand response options that deliver net cost savings to their customers, where it is efficient to do so. We would need to see further details of such a proposal, in particular the methodology for the levying and recovery of payment to the Fund and the calculation of incentive payments to retailers before determining support or otherwise for the proposal.

The complicating factor in all of the above options is that the true extent of demand response is opaque for the casual observer. Many of the arrangements are commercial-in-confidence and a range of service providers, including but not limited to energy retailers, provide the service. This masks the true level of demand response currently available in the NEM but does not mean that there isn't the potential for additional demand response that provides efficient outcomes in the long-term interest of consumers to be unlocked. We would also add that the reliability guarantee as part of the NEG may provide an additional incentive for retailers to offer demand response.