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Australian Energy Market Operator
GPO Box 2008
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RE: 2019 Planning and Forecasting Consultation Paper

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Operator's (AEMO) 2019 Planning and Forecasting consultation paper. This paper commences consultation on scenarios, inputs, assumptions, methodology and timelines for AEMO's forecasting and planning publications, including the NEM Electricity Statement of Opportunities (ESOO) and the Integrated System Plan (ISP).

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. The Company operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland. www.ermpower.com.au

General comments

ERM Power welcomes opportunities to contribute to on-going consultation on the scenarios, inputs, assumptions and methodologies used by AEMO to forecast and plan for the evolving National Electricity Market (NEM). With the NEM undergoing significant changes in types of supply and consumption behaviour, the importance of comprehensive and rigorous planning and forecasting of the NEM cannot be over-emphasised. The critical nature of planning and forecasting output is driven by the current rate of transition, illustrated by the volume of regulatory and legislative reforms currently underway and growing public expectations on price outcomes, supply reliability and emissions standards. Considering the importance of AEMO's assumptions and modelled scenarios, open and consistent consultation in essential.

ERM Power believe that work is required by AEMO to improve the transparency and accuracy of input assumptions and the open communication of calculated outcomes. AEMO has stated that consultation on the inputs and assumptions will be used to support an actionable ISP and forecast regional energy consumption and maximum demand through the ESOO. The ESOO will be relied upon for forecasting reliability gaps under the Retailer Reliability Obligation (RRO), following a trend of forecasting and planning publications shifting from information-only documents to publications used for decision-making purposes. In the context of the RRO and the ISP, AEMO's planning forecasts are likely to significantly impact market participants, affecting investment decisions, contracting positions and consumer costs.

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

In the following discussion, ERM Power has provided feedback on AEMO's overall approach to planning and forecasting. Please refer to the technical addendum at the conclusion of this submission for technical feedback on specific inputs and assumptions in the modelling.

Transparency of data and forecasts

Market players and investors are looking to government decision-making and market institutions to enable access to competitive markets and foster an attractive environment for strategic investment. To this end, AEMO will be publishing the 2019-20 ISP and 2019 ESOO in the coming months. ERM Power believe that there are targeted areas of focus for AEMO to improve confidence in their planning function, and provide transparent, accessible and consistent forecasts.

Transparency and consistency of network capability and forecasting are key to providing a favourable investment environment. However, anecdotal evidence from industry has identified that a lack of transparency regarding network capability has resulted in project delays, in tandem with an increased regulatory focus on reliability obligations.

ERM Power's submission to the AEMC's Coordination of generation and transmissions investment review highlighted the need for improvements in AEMO's information provision to the market, particularly accurate network congestion data in the form of uncongested headroom, and related connection data at various connection locations. We also believe improvements to data on AEMO's Generation Information Page could be achieved through inclusion of connection point data for committed and advanced generation projects. Improving data transparency will provide market participants with clearer insights on the likelihood of future market and network scenarios, and incorporate this information in their investment decision-making. We believe these actions will encourage confidence in the planning function and processes established in the NEM.

Perception regarding AEMO's conservative approach to modelling assumptions

Improving transparency and consistency is one factor of the planning and forecasting process which can contribute to improving stakeholder confidence in the 2019-20 ISP and 2019 ESOO results. Investment decisions for new plant and futures contracts are analysed and negotiated based on planning and forecast scenarios provided by planning documents, such as the Medium Term Projected Assessment of System Adequacy (MTPASA) and ESOO.

ERM Power believes that AEMO generally employs a conservative approach when determining the assumptions which underpin their modelling. We believe that AEMO should evaluate the relevance of conservative assumptions currently applied to their modelling, and consider the historical performance of their modelling assumptions to determine future approaches.

It is our view that conservative modelling assumptions have an observable impact on forecasting, with evidence to suggest that AEMO consistently applies a conservative approach to medium and long term maximum regional demand forecasting. Conservative approaches in these modelled forecasts flow through to investment and financial decision-making, increasing overall costs and barriers to participation. It can be argued that consistent over-forecasting of medium and long term maximum demand places unnecessary costs on the market, with commercial decision-making intrinsically linked and partially dependent on forecast maximum demand for supply in the NEM. ERM Power has submitted comments to AEMO's Demand Forecasting Methodology Information Paper consultation regarding improvements which could be made to AEMO's demand modelling approach, which should be considered as applicable to this consultation.

In addition, conservative maximum demand forecasts impact the requirements for network investment, overstating the need for new network investment to meet consumer reliability requirements. Consumers bear the cost for overinvestment in the network. To reverse this trend, it is critical that the accuracy of AEMO's maximum demand forecasts be improved.

Role of the ISP and ESOO

As AEMO has identified, planning and forecasting publications are currently being used as a basis for investment decision-making. ERM Power emphasises that historical AEMO planning documents have demonstrated that forecasted futures often significantly deviate from the real outcomes[2]. ERM Power believes it is important to emphasise that the published forecasts should not be used as a basis for accelerated investment decisions or market intervention. Hastened action to construct long-lived network assets may result in unnecessarily high costs to consumers.

ERM Power believes the primary function of the ISP and ESOO should be to transparently communicate as wide a range of plausible scenarios which can be achieved within the timeframe allocated. In selecting plausible scenarios, AEMO should direct greater emphasis towards providing comprehensive description and discussion on the scenarios provided to allow more informed review and commentary by external parties. The role of pricing outcomes and signals for transmission investment should be addressed in the modelling.

Interaction with the Retailer Reliability Obligation

In light of the legislative reform processes currently underway, the need for improved rigour in AEMO's forecasting reports is significant. As AEMO has identified, planning and forecasting publications are transforming from planning information documents to guidelines and actionable plans, being consulted by market participants for commercial decision-making and regulatory compliance purposes. Currently, we are concerned that AEMO's planning and forecasting documents remain unfit for purpose in that regard.

The COAG Energy Council has agreed to progress the development of the RRO. Although the RRO has not been explicitly identified as a key policy setting affecting energy supplies in the Consultation Paper, ERM Power hold the view that the RRO must be considered through AEMO's forecast modelling exercises to produce transparent and useful information. The forecasting scenarios should be improved to provide sufficient information to market participants to manage compliance with the RRO, and procure the necessary resources to allow a defined 'gap period' to be closed by market participants in the most efficient way.

Once legislated, the RRO will require retailers to hold sufficient qualifying contracts during a defined reliability 'gap period'. A gap period will be identified based on the forecast outputs of the ESOO. We currently understand that the gap period will be a defined set of trading intervals, signalled three years in advance (T-3 years), with a further confirmation of at least one year in advance (T-1). Output from the current ESOO process will need to be significantly expanded and communicated in greater detail before participants can be confident that outputs from the ESOO assessment process are fit for purpose for interaction with the RRO.

ERM Power believes that any gap period(s) must be as narrow as reasonably achievable. Longer gap periods which are less targeted may signal requirements for larger-scale investments in generation facilities which require decadal payback periods. Conversely, hourly gap periods would allow for alternative firm options such as demand response and battery storage technology to meet to the reliability gap.

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[2] It should be noted that in the AEMO 2009 ESOO, the forecast energy consumption for Victoria was for 12% growth by 2018/19 and a summer 10 % POE peak demand of approx.13,700 MW. Had an ISP in 2009 driven generation and network investment to match these forecasts, significant overinvestment in both would have occurred which would have led to both higher prices to consumers as well as a damaging loss of confidence in the Market as a whole. We are concerned little has changed in this regard, AEMO's 2018 ESOO forecast growth of 2.3% in grid delivered energy for Victoria in FY 2018/19, FYTD Victoria grid delivered energy compared to the same period in FY2017/18 has actually reduced by 2.4%.

As the purpose of the RRO is to signal the need for increased levels of firm supply to address a defined reliability gap, sufficiency of temporal resolution of planning forecasts for defining the reliability gap must be addressed. ERM Power is seeking to increase the accuracy of the ESOO by providing forecasting information of a temporal resolution sufficient to identify gap periods across hourly timescales.

Frequency of publication of the ISP

The ISP has potential to play a critical role in the future planning and investment of the NEM. To support the development of an optimal planning process, it is critical that adequate time is allocated to the development of the ISP. ERM Power believe this should include the progressive communication of AEMO's detailed data assessment to stakeholders for review and input, and a periodic review of the modelling process to ensure its relevance is maintained in the context of a changing supply-demand environment.

The modelling and analysis required to produce the ISP is a detailed and multi-staged process. ERM Power believe that AEMO should detail all outcomes and supporting data from the initial draft modelling process that was used to prepare the initial draft ISP publication, and provide sufficient time for external review of the published information prior to the commencement of works for finalisation of the ISP.

Given the potentially critical role the ISP may be allocated in the future, it is important that adequate time is allocated to the process as a best-practice approach for the development and publication of planning information. To this end, we offer for consideration that the ISP be published on a biennial rather than annual basis.

Conclusion

ERM Power welcome the work undertaken by AEMO to improve planning and forecasting processes in the NEM. However, we believe that there are improvements which can be employed to increase transparency of data and manage the impact of conservative forecasting. We also make a number of suggestions to improve the rigour of the ISP process and emphasise the importance of practising caution when using planning outcomes to accelerate investment decisions. Finally, it is important that planning outcomes are fit-for-purpose for use by market participants in ensuring their compliance with the RRO.

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

Yours sincerely,

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Technical addendum

Scenario development

Currently, AEMO have developed 3 "bookend" scenarios - one neutral, one fast change and one slow change, including an alternative neutral scenario of increased distributed energy resources. AEMO acknowledge in developing the fast change scenario that this is designed to stretch the need for development of the transmission network to meet future expanded consumer demand from geographically diverse generated electricity. We believe there should be further examination of variants to the fast change scenario. For example, flatter duration curves, lower maximum demand, changes to transport fuel and transmission expansion patterns are all varying factors which could be investigated in a fast change scenario.

Whilst it could be argued that the boundaries of future generation and transmission development could lay between these "bookends", in the case of the more extreme fast change scenario, the level of additional generation and transmission development required would be significantly higher than that of a more plausible view of a fast change world where the fast roll out of intermittent generation and early retirement of the existing coal fired fleet leads to the exit of energy intensive consumers such as aluminium smelters and their associated support industries. For these reasons we believe that rather than only undertaking modelling to test the bookends, additional modelling of plausible scenarios within the boundaries of these "bookend" scenarios is required.

We recommend as a minimum that the slow change scenario also be modelled with a high GDP and high energy consumption and demand outcome, and the fast change scenario be modelled with a low GDP and low energy consumption and demand outcome. The summary results of recently released modelling undertaken by BAEconomics has indicated that in the fast change world of expedited roll out of VRE, GDP is expected to be lower than in the business as usual scenario. Similarly, GDP may be higher than that considered in the current slow change scenario. For this reason we believe that the proposed scenarios need to be examined more closely to better understand the changed incentives for capital expenditure in transmission and generation for changes in GDP assumptions.

Emission reduction trajectory

Currently, the proposed modelling methodology does not include as an input emission reduction trajectories to meet the Paris Agreement target commitment 26% or higher emissions reductions scenarios likely under a fast change scenario. We understand from the Paper that emissions reductions are achieved by altering the timing and size of forced retirement of coal fired generation as an input to the modelling. We do not support this approach and believe the emission reduction trajectory should be a discrete input to the modelling process, which would then allow the trajectory to be met on a least cost approach basis.

Generator retirement provision

Currently, the proposed modelling methodology has discrete inputs to force retirement of existing generation capacity at designated points in time. We do not support this as a modelling input assumption. In our view, there are a number of factors which should be considered when projecting generation retirements, including revenue adequacy, operating and maintenance costs and the likelihood of plant refurbishment.

Generator retirements should be a function of revenue adequacy rather than a forced retirement date based on an arbitrary service life.

Plant maintenance and refurbishments

When considering revenue adequacy, the potential for plant modifications for the extension of plant life should be considered. Plant modifications to allow operation at lower minimum loads and facilitation of weekend or short duration cycling are feasible. To date, economic outcomes may have been insufficient to justify such plant modifications for plants nearing the end of their "economic" life, but the capacity for this to occur should not be overlooked for plants with a longer remaining life. There is strong evidence from Germany that economic signals (low or negative pool prices) have led to traditional baseload plants successfully transitioning to more flexible plants that can provide better firming in an environment of increased levels of renewable generation.

Currently, fixed costs for generation is expressed in simple terms of $/KW of installed capacity/year as a modelling input. In considering the appropriateness of this for modelling generation revenue adequacy, we believe consideration should be given that maintenance regimes for large thermal generation are often planned on the basis of operating hours in-service, as opposed to a simple calendar period basis. A four unit station with a 28,000 hour maintenance requirement could in effect only have one major unit outage every year if units in-service were cycled to include 25% of days out of service per year. In considering the revenue adequacy perspective for large coal fired units, we believe the modelling should allocate fixed costs on the basis of days in-service. By way of example, a 700 MW coal fired capacity would currently be allocated a fixed cost of $3.72M/year regardless of days in-service, alternatively, for the modelling the unit could also be allocated a fixed cost of $102K per operational day.

In considering potential for upgrades to extend life of existing generation, we note that the modelling allows for consideration of major refurbishment works such as turbine replacement or replacement of creep affected components, we support this inclusion. However, we also note that for existing generation, the modelling inputs data whilst containing details of original commissioning date, fails to consider that works such a turbine replacement or replacement of creep affected components many of which have already occurred within the last 10 years. Given that these significant works would be expected to extend the operating life of a generating unit for 25 to 30 years, we believe the modelling inputs data-base would benefit from this understanding, or those that are planned to be completed within the planning documents horizon. We also consider the values contained within the modelling inputs of $1,300/KW for turbine replacement and up to $450/KW for replacement of creep affected components to be excessive. We understand that actual costs would be no greater than 20% of these values.

A significant hurdle in the consideration of costs for retirement of existing generation is the costs of demolition and rehabilitation of the power station site. We note that the modelling inputs allow for these costs to be factored in to the revenue adequacy calculation, however, no cost in $/KW of installed capacity is currently included; we believe cost estimates should be included in this area.

External fixed and maintenance operating costs

We also note that AEMO has proposed to also include the fixed operating and maintenance costs of mines supplying coal to the relevant power stations fixed operating and maintenance costs. In doing so we believe AEMO should first determine if the marginal costs of fuel allocated to that power station includes such costs to ensure double counting of costs does not occur.

Historical ½ hourly demand and intermittent generation output traces and reference years

Currently the proposed modelling methodology utilises up to eight reference years to compile ½ hourly demand and intermittent generation output traces to be used in the modelling. With the forecast for expanding levels of generation with intermittent output based solely on prevailing weather outcomes, we believe that the use of up to only eight reference load trace years be should be reassessed to ensure that sufficient years are employed to adequately capture the full range of historical outcomes experienced across the high level of geographical diversity that encompasses the NEM. We also believe it would be beneficial that planning documents include details of the actual reference years used in their preparation, with an accompanying explanation as to how the reference years chosen were selected and how they cover the range of observed historical outcomes.

Candidate generation technology options

ERM Power supports the work to date undertaken by AEMO and its consultants to better understand and quantify the costs of the various generation technology options. With the NEM shifting to 5 minute settlement regime, the potential introduction of a voluntary day-ahead market and increasing commissioning of intermittent generation, generating plant that have the capability for a high degree of operating flexibility and capability to provide power system support functionality will provide increasing multiple benefits in the future NEM. We believe that improved granularity in the area of costs for open cycle gas turbines is required as inputs to the modelling.

For example:

OCGT – Frame type of two sizes in the range of 150 to 280 MW

OCGT – Frame type of two sizes in the range of 150 to 280 MW with synchronous condenser operating capability

OCGT – Aeroderivative type of two sizes in the range 40 to 120 MW

OCGT – Aeroderivative type of two sizes in the range 40 to 120 MW with synchronous condenser operating capability

We also note AEMO's planned exclusion of gas or liquid fuelled reciprocating engines from the modelling. ERM Power believes this planned exclusion should be reconsidered. We also consider that project size for reciprocating engines of 220 MW be reduced to 50 MW block increments to better model the size of expected entry.

Storage technology options

ERM Power supports the work to date undertaken by AEMO to better understand the economics of storage technology. There are two significant considerations regarding modelling of battery storage that do not appear to be considered in the modelling input assumptions

- The yearly costs to maintain the minimum level of storage as the capability of a battery to store energy deteriorates over time
- The cost of safe environmental disposal of used batteries at the end of their expected ten year life

We believe appropriate costs for these must be included in the modelling.

We support the choice of 6, 12, 24 and 48 hour storage options for hydro pumped storage facilities. We also note AEMO's proposal for maximum build limits applying to these different levels of pumped hydro storage on a region basis and request AEMO provide additional details to justify these limits.

We also note AEMO's round-trip efficiency allocation of 90% to batteries and 76% to pumped hydro. We believe AEMO should review the energy charging and discharging history for existing NEM batteries prior to allocating a round-trip efficiency of 90% to batteries in the modelling. We consider that actual outcomes provide a more accurate evaluation of battery performance.

Whilst we support consideration and modelling of storage options, ERM Power remains concerned that simple storage option solutions as proposed may be insufficient to ensure ongoing supply reliability. As noted previously, we remain concerned that the use of only up to 8 reference years may fail to cover the full range of energy inputs to intermittent generation due to the vagaries of weather outcomes. We request AEMO provide further information based on the modelling outcomes regarding what capabilities are provided by storage solutions or alternatively by open cycle gas turbines or reciprocating engines to ensure generation resource adequacy over the long term to ensure reliable supply to consumers.

Renewable energy zones

ERM Power supports AEMO's work undertaken in the inaugural 2018 ISP to identify and rank renewable energy zones (REZs). To contribute to the accurate ranking and comparison of the REZs, we believe that a holistic approach is required to assess the potential for each individual REZ to provide benefit to the market. Data which could assist in comparison of REZs include:

- expected generator output (expressed in terms of percentage of installed capacity) at the time of summer and winter peak regional demand
- cost of development of deep transmission connection from the REZ to satisfy regional demand requirements

In assessing the cost of deep transmission connection, we believe costs should be based on network development from the REZ to the existing network, and assess any resulting network congestion on the existing network.

In addition, the 2018 ISP proposed lengthy routes for interconnection between regions to facilitate lower REZ connection costs. As noted in our submission to the AEMC's Coordination of Generation and Transmission Investment Review, we do not consider that inflating interconnector costs would in all cases lead to efficient network investment and support justification for lower REZ connection costs. We believe costs should include the identifiable marginal costs of modifying interconnector routes to facilitate REZ connection. This could include a direct $/km cost comparison between the length of the direct route and the route proposed in the ISP.

Consideration of new markets for power system support services

The rate of change occurring to date in the NEM is already leading to difficulties in the provision of power system support services. Issues have been observed in South Australia, Victoria and to a lesser extent NSW where Directions have been issued to generators for the provision of power system support services in the previous 12 months. AEMO have also indicated that the issuing of Directions for power system support services can be expected to occur in Tasmania and Queensland within the next 12 to 24 months.

We believe the ISP should consider what new markets will need to be developed to ensure the ongoing secure operation of the power system and to ensure reliable supply to consumers into the future. By way of example, markets for the provision of ramping services to cope with the role off of solar PV during the lead into the evening peak period, particularly in the April to September months, noting that a number of overseas markets already procure services for the provision of this. In addition, could system strength and inertia services be provided by the provision of dual purpose gas turbines or pumped hydro designed to also operate in synchronous condenser mode as opposed to the current trend for Network Services Providers to provide this as an additional regulated service paid for by consumers. Would markets for the provision of power system support services ultimately deliver these services at lower costs than the current provision of these support services as a regulated network service.

Penetration of distributed energy resources

AEMO has correctly identified that the distributed energy resources (DER) across the NEM will continue to increase. ERM Power suggests that the forecast uptake of DER would be improved through the consideration of the following technical factors impacting uptake:

- The ability of the current distribution network to facilitate increasing roll out of DER
- Estimates of additional costs to facilitate the increased roll out of DER
- The impact of potential changes to network tariff structures on the future roll out of DER
- Ongoing maintenance and disposal costs

- Potential saturation levels for DER
- Potential impacts of DER on power system resilience of increased DER

We recognise that work is underway between AEMO, ARENA and the CSIRO on the uptake of DER in the NEM. Stakeholders do not yet have access to the detail of this work program. For the current ISP, consultation with distribution network services providers could reveal what level of DER could be supported in current existing networks. Improvements to the ISP on DER should be incorporated prior to use by ARENA for DER modelling analysis.

Network constraint equations used in 2019 modelling

We note that the consultation paper indicates that a workbook setting out constraints used in the 2019/20 ISP and ESOO modelling will be issued with the 2019/20 ISP. We believe that currently known constraint equation which will be utilised in the 2019 modelling should be issued for review and comment similar to how other input assumptions have been released for review and comment prior to commencement of modelling. Additional constraint equations developed during the modelling process could then be released as an addendum to the original constraint set with the 2019/20 ISP.

We support AEMO's decision to only use system normal network constraints for the modelling process.