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Thursday, 21 November 2019

Mr John Pierce AO
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

RE: ERC0282 – Application of compensation in relation to AEMO interventions

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (the Commission) Consultation Paper (the Paper) to the rule change requests submitted by the Australian Energy Market Operator (AEMO) for the Application of compensation in relation to AEMO interventions.

About ERM Power

ERM Power is an Australian energy business for business. ERM Power provides large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fueled 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 Power also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

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General comments

ERM Power does not support the proposed rule change. Similar to the concerns raised about the Draft Determination for the Application of the Regional Reference Node (RRN) Test to the Reliability and Emergency Reserve Trader (RERT), we believe this rule change will result in unintended consequences which will unnecessarily increase the costs of compensation from AEMO's intervention on the normal functioning of the National Electricity Market (NEM). These costs are ultimately paid by consumers

We believe that due to the distortionary impact of the Direction and the loss of affected participant compensation additional generating units, who would otherwise continue to provide the necessary power system services, such as system strength, inertia, and voltage control, may self de-commit from the Market due to the loss of affected participant compensation. AEMO will then be required to issue additional clause 4.8.9 Directions to generators to maintain the power system in a secure operating state.

It is our view that overall the proposed rule changes, if implemented, will lead to an increased frequency of market intervention in the form of the issuing of additional clause 4.8.9 Directions to generators. In turn, this will increase costs for consumers due to increased directions compensation payments than would otherwise be the case if the current affected participant compensation framework continued. This issue has not been considered in the Paper and we ask that the Commission consider and quantify the impact of such an outcome in the Final Determination.

We also note that the original intent for the addition of affected participant compensation framework in the Rules was to ensure that when the market operator intervened in the market in the form of a Clause 4.8.9 Direction, the distortionary impact of the Direction on market dispatch outcomes was removed. We do not believe that this proposed rule change removes the distortionary impacts of Clause 4.8.9 Directions.

Compensation for intervention vs network constraints

In the Paper, the Commission considers that the impact on participants due to the distortions on the market from AEMO's intervention is similar to that associated with network constraints. We do not agree with the Commission's view. The impact of network constraints is a normal feature of market operations whereas intervention results in a direct distortion of normal functioning of the market. Whilst a generator could have its dispatch outcome altered because of a network constraint, this is because the generator dispatch must be altered to maintain secure operation of the power system. The actions by the generator, to generate output higher than the capability of the transmission network at that time, directly causes the need for its dispatch outcome to be altered. This is not the case where AEMO distorts the market by direct intervention.

We note the example regarding Mortlake Unit 2 on 1 December 2016 in the Paper. In this instance, the operation of the Mortlake unit caused a power system security issue to occur during an outage of one of the network flow paths between Moorabool and Heywood in Victoria. Operation of the Mortlake unit led to a voltage imbalance in the network which could not be managed through the use of the network constraint equations invoked by AEMO to manage the power system during the planned outage. Only the full shutdown of Mortlake Unit 2 could alleviate the power system security issue. As set out above, it was the action of the generator, at that point in time, that directly led to the insecure operation of the power system.

However, an affected participant's dispatch outcome is altered because of intervention in the market by the market operator to cause another generator to generate unpriced energy[1] to provide a service required by the power system at a price where the Directed participant would not otherwise freely choose to do so. In this case, a network constraint is unable to constrain on a generator's output against the generator's de-commitment decision, so a Direction is required to be issued. This leads to an affected participant's output being altered to a different level than it otherwise would be, absent the intervention. In this instance, the affected participant, (who is not by their actions leading to the need for market intervention), would not receive compensation under the proposed rule change for actions by the market operator which impact their commercial position. In this respect we believe the proposed rule change fails the assessment framework in the area of equity, in that the proposed approach does not strike a fair balance between the interests of affected participants and consumers. We believe that the Commission should give greater consideration to the fact that an affected participant is required to incur costs up to $5,000 per trading interval before compensation for that trading interval is payable, for a lengthy market intervention, this could amount to uncompensated costs of $240,000 per day.

We also note the argument that affected participant compensation would not be paid if the provision of the power system service could be achieved from a network service provider or operation of a generator in synchronous condenser mode either via a Direction or a Network Support and Control Ancillary Services contract. We agree that would be the case, simply because there would be no associated distortionary impact on dispatch where dispatch outcomes were actually altered. Switching of network infrastructure or operation of a synchronous condenser does not directly add unpriced energy dispatch in the market. Absent an alteration in dispatch outcomes, there is no affected participant and therefore no requirement for affected participant compensation.

[1] In the event of a Direction that adds energy dispatch to the Market, this energy dispatch is considered by the dispatch engine to be priced at the market floor price.

Ability to optimise affected participant compensation

In the Paper, the Commission considers that it is theoretically possible for a participant(s) to optimise affected participant compensation. We believe that in practice this may be difficult to achieve.

If an affected participant were to *increase* the volume in lower priced bid bands in an attempt to maximise volume for affected participant compensation this would result in:

- Displacement of other higher priced generation from dispatch and an increase in the affected participant's dispatch output, which would lead to a decrease in volume subject to compensation for that participant;
- A reduction in the published Regional Reference Price (RRP) – as the affected participant compensation is the net of marginal costs, this would lower the compensation amount payable, and
- Increased risk that this could reduce the affected participant compensation payable below the $5,000 trading interval threshold so no compensation would actually be payable.

If an affected participant were to *decrease* the volume in lower priced bid bands in an attempt to maximise the RRP for affected participant compensation this would result in:

- A reduction in the volume subject to displacement by the direction – depending on the revised net price differential and reduction in displaced volume, this could lower compensation payable, and
- Increase the risk that this could reduce compensation payable below the $5,000 trading interval threshold so no compensation would be payable.

It is our view that given that dispatch outcomes change every 5 minutes, trying to achieve a compensation optimisation strategy would be at high risk of failure.

We note that the Commission considered the level of affected participant compensation paid between April 2017 and April 2019 and found that the net level of affected participant compensation was not large when considered in the context of the volume of energy traded in the NEM. However, the Paper then implies that the occurrence of one participant receiving thirty percent of the total of affected participant compensation may be evidence of a participant's ability to optimise the level of compensation payable. The Paper fails to consider whether the payment of affected participant compensation to this single participant may have been due to this participant being utilised by AEMO for counteractions on a frequent basis within the region where the Direction occurred. The Paper does not contain any details of specific examples where it is clearly demonstrated a compensation optimisation strategy has been deployed. It would be helpful for the Commission to point to examples where the Commission believes such a strategy has been implemented during a period where a Direction prevailed.

AEMO systems and practical implementation

Both AEMO's rule change request and the Commission's Paper noted the practical implementation aspects if the affected participant compensation framework remained unchanged following implementation of a final determination with regards to the Regional Reference Node Test (RRN test) rule change. The Draft Determination proposes to remove the requirements that a Direction for a non-traded market commodity, such as one of the power system services, which could be provided by a notional unit at the regional reference node, would automatically fail the RRN test and intervention pricing would not be triggered.

Currently, the level of compensation to an affected participant is determined by the level of dispatch distortion on the affected participant's generating unit due to its displacement by the Directed participant's generating unit. This is multiplied by the intervention price less the affected participant's generating unit's short run marginal costs as determined by AEMO. AEMO argues that if intervention pricing is not triggered, AEMO would not need to trigger an intervention pricing run and therefore would have no intervention price or the level of dispatch distortion.

We note however, there would be no barrier to AEMO still undertaking an intervention run to determine the dispatch distortion while maintaining the dispatch price outcome based on the Outturn run.

AEMO currently has the automated systems developed to calculate the Outturn run in real time, which is then used to calculate the dispatch distortion on affected participants' generating units. This existing system would only require a minor modification to allow selection in the Outturn run of either Outturn or What-If run pricing outcomes. We do not believe this represents a significant cost impost for AEMO to modify their existing system.

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

Yours sincerely

[signed]

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