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Thursday, 16 May 2019

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

Dear Mr Pierce

EPR0070 Investigation into Intervention Mechanisms and System Strength in the NEM

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (the Commission) Investigation into intervention mechanisms and system strength in the National Electricity Market Consultation Paper (the Paper) issued April 2019. We note that this review also includes consultation on the Australian Energy Market Operator's (AEMO's) rule change requests, Threshold for participant compensation following market intervention and application of the Regional reference node test following activation of the reliability and emergency reserve trader.

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

The National Electricity Market (NEM) is in a state of transition, with forecasts for increasing penetration of intermittent output generation, (which, due to their input energy type, are at best only able to be semi-scheduled[2] by the market operator), replacing fully schedulable generators which also supply power system security services. Through the transition phase it is essential that a sufficiently flexible approach be maintained that allows as much as possible the ability for market-based responses to emerge prior to the invoking of market intervention by the market operator. As noted by the Commission in several reviews of various market frameworks and rule change consultations, and supported by the majority of participants and consumer organisations, market-based approaches compared to centrally-planned outcomes are more likely to deliver the greatest benefits over the long-term to consumers.

1 Based on ERM Power analysis of latest published financial information.
2 AEMO may only impose an output cap on Semi-Scheduled generation

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The Commission, through a number of rules changes, which have been in effect for less than 12 months has significantly altered the NEM frameworks for the timely provision of various power system services. In considering changes to the current intervention frameworks, we urge the Commission to consider these relatively recent changes implemented after the emergence of issues regarding the provision of power system services in South Australia and allow the benefits of these changes to transpire before recommending any significant additional changes as part of this review.

Summary of issues and assessment approach

In considering the issues raised in the Paper we agree with the Commission's assessment that:

> *"intervention-based approaches, however well designed, are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets are generally the most efficient mechanism to further the interests of consumers through allowing efficient price discovery and production decisions based on competitive market dynamics."*[3]

Whilst the Paper summarises the suite of market intervention mechanisms and current perceived issues fairly well, with regards to both the frequency and duration of system strength directions in South Australia, ERM Power questions if an intervention regime was imposed both too quickly and of too significant size in terms of asynchronous generation output to the detriment of allowing a market response to develop.

In the case of the system strength directions regime imposed in South Australia, a decision was made to maintain sufficient synchronous generation on-line to facilitate a minimum level of constraint on asynchronous generation operation of initially 1,200 MW (revised to 1,295 MW) on an N-1 generator basis. This N-1 Direction level was initially imposed regardless of the forecast of expected asynchronous generation output and the ability of available stand-by fast start units to restore system security to satisfactory levels within the allowed 30-minute period following a unit failure. Until this regime was imposed on the Market, which occurred with little notification, it was not historical practice for the market operator to maintain a minimum number of synchronous generators in-service via the use of a clause 4.8.9 Direction to allow a specific minimum level of synchronous or asynchronous generation access to the market. We are concerned that by setting such a high level of minimum asynchronous generation constraint, barriers to the development of normal market based responses were imposed, to the detriment of consumers.

In response to the emerging system strength issues in South Australia, we believe an alternative framework which allows varying levels of constraint on asynchronous generation output for different numbers of synchronous generation could have been transparently advised by AEMO, even if this had occurred over a delayed time period. In our view, this alternative framework would allow lower levels of asynchronous generation output constraint: as low as 600 MW for lower numbers of in-service synchronous generators (2 instead of the normal 4 to 5). This would reduce both the frequency and duration of AEMO system strength Directions and ultimately costs to consumers. This alternative framework would in our view allow for market-based responses where the efficient level of synchronous generators in-service for varying levels of asynchronous generation output would develop without the need for market intervention. It would also prevent the current situation where generation portfolios which contain both synchronous and asynchronous generation resources, either directly controlled or via contractual arrangements, benefit from both compensation for Direction and higher asynchronous generation output, the additional cost of which is borne by consumers.

In considering the questions around the assessment principles with regards to the NEM intervention framework we believe the Commission should give consideration to the issues raised above including the provision of independent advice. We agree with the assessment principles as proposed in the Paper and offer the following additional assessment principles for consideration by the Commission.

[3] Page 14, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

Technology neutral: Regulatory arrangements should be designed to take into account the full range of potential market solutions. They should not be designed to provide increased benefits to a particular technology or be designed with a particular set of technologies in mind.

Market mechanisms: Competition and market signals, where feasible, generally lead to more efficient operational decisions than market intervention. These outcomes are generally more flexible to changing market conditions and provide consumers with the services in the most efficient manner possible. For competition to be effective, it must be able to deliver market signals to parties best able to respond to these signals in a manner that benefits consumers over the long term.

Regulatory certainty: Clear regulatory responsibilities for AEMO for both the timing and the extent (size and duration) of market intervention. Given the changing nature of supply including the increasing level of distributed energy resources, greater clarity regarding the use of market intervention and the reporting requirements for any market intervention should be considered. It should be clearly demonstrable that market intervention is only imposed as a last resort and only to the extent necessary to manage prevailing power system conditions.

Principles applicable to intervention mechanisms

We agree with the Commission that there may be benefit in amending the principles, particularly the alignment of “minimising cost to end use consumers of electricity” for Directions similar to that stipulated for exercise of the Reliability and Emergency Reserve Trader (RERT) to promote internal consistency to the extent appropriate. As discussed above, we consider that review of the reporting requirements associated with market intervention is warranted and the reporting requirements should more closely mirror the amended RERT reporting requirements[4]. The reporting requirements for market intervention should require clear demonstration of both the need for and the extent of market intervention as well as the costs of market intervention.

Hierarchy of intervention mechanisms

We agree with the Commission’s view that the rationale for prioritising the exercise of RERT over issue of a Direction is less obvious than the rationale for exercising the RERT ahead of an Instruction which results in involuntary shedding of customer load[5]. We agree that in some cases, issue of a Direction to a generator may result in lower overall costs to consumers than the exercise of a RERT contract. We believe that the market operator should be required to determine the lowest cost option for consumers, either exercise of a RERT contract or issuing of a Direction, prior to any exercise of its market intervention powers. This should apply regardless of the need for market intervention – power system security or supply scarcity. We would support an amendment to clause 3.8.14 (b) to allow either exercise of a RERT contract or issue of a clause 4.8.9 Direction based on the assessed lowest overall costs to consumers at the time of market intervention.

We would not support an arbitrary amendment which required issuing of a Direction prior to exercise of a RERT contract without the requirement for assessment of overall costs to consumers.

The amendment as discussed above would also remove the potential which exists in clause 3.8.14 (c) of the Rules where an Instruction for involuntary shedding of customer load could be issued prior to a Direction. Whilst this has not occurred to date, we believe removing the potential for it to occur from the Rules would be beneficial.

[4] Amended NER clause 3.20.6 Enhanced RERT Rule Change

[5] Page 35~~,~~, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

Mandatory restrictions

The mandatory restrictions provision is the most “blunt” of all the potential market interventions which can be imposed in the NEM. Mandatory restrictions would generally be imposed by the relevant jurisdiction following advice from the market operator that a significant supply shortfall is forecast in the pre-dispatch period, as such, it is critical that all advice supplied by the market operator to the Jurisdictional System Security Coordinator in this regard is transparently conveyed to the Market in a timely manner. This is currently not a Rules requirement.

As discussed in the Paper, there are negative aspects of the Rules governing the mandatory restrictions process, not least of which is the potential for inaccurate assessment of the estimated demand reduction on a per trading interval basis. Errors in the estimation of demand reduction due to mandatory restrictions may result in price outcomes that may on average be higher or lower than would have occurred had the estimate of demand reduction due to restrictions been of a reasonable level of accuracy.

The Paper proposes the use of intervention pricing, as opposed to mandatory restrictions contracting, in circumstances where mandatory restrictions are applied. However, the Paper is unclear regarding the application of clause 3.12.2 - Affected Participants and Market Customers entitlements to compensation in relation to AEMO intervention. A major benefit of the current provisions is that where mandatory restrictions are applied in a Region, the impact of this blunt market intervention is to an extent confined to that region by the current mandatory restrictions provisions. Removing the mandatory restrictions provisions and replacing them with only the intervention pricing provisions would result in the impact of mandatory restrictions in a region being transferred to other regions of the NEM. From a market distortion impact we consider that this would be a negative outcome.

Whilst the market distortion impact could be reduced by application of the clause 3.12.2 compensation provisions, this would increase the total costs of compensation payable by consumers and may impact costs to consumers in regions in which mandatory restrictions do not apply. It is also worth considering that the competitive nature of bidding for the provision of restriction offers may result in lower overall market costs than the proposed alternative.

Taking all these factors into consideration we believe that the mandatory restrictions framework should be retained as per current arrangements. We note that this is the most “blunt” of all market interventions and as such must only be used as the absolute last resort in the market intervention hierarchy. Additionally, it highlights the need for all communications between the market operator and the jurisdiction(s) to be transparently communicated to the Market in a timely manner which may in turn stimulate additional in-market or offers for additional RERT response.

Use of intervention pricing

ERM Power supports the continued use of intervention pricing provisions in their current form including the use of the regional reference node test. We consider that the use of intervention pricing to maintain the market pricing outcomes that would have occurred absent market intervention by the market operator is a critical outcome for the removal of the market distortion introduced by the market operator through the imposition of a market intervention where additional energy supply is dispatched, regardless of the cause of such market intervention.

In the Paper, the Commission sets out that whilst intervention pricing does not cause spot price outcomes to rise, in effect it fails to allow spot prices to fall in response to the additional energy supply due to the market intervention. In doing so, the Paper fails to consider that this additional supply would not have been dispatched absent intervention by the market operator. As such, intervention pricing necessarily removes the market distortion caused by the action of the market operator and reflects the accurate price outcome for the market.

Counteractions implemented by the market operator to limit the distortionary impact of market intervention and minimise the number of affected participants are a useful feature of management by the market operator of the distortionary impact of their action.

The implementation of effective counteraction by the market operator, particularly when applied in the same region as the intervention would result in the dispatch price and the intervention price being the same, as energy withdrawn within the region due to the counteraction would be equal to the additional energy injected due to the intervention. We support the continued use of counteraction measures by the market operator. We understand that this is currently undertaken as a manual process at Dispatch and note that AEMO's Intervention Pricing Working Group (IPWG) that was convened by AEMO to review their intervention pricing methodology reviewed the current counteraction process and recommended the continued use of counteractions and that AEMO consider the automation of this process where possible. We also consider that this automation be a useful improvement to AEMO's current process.

In considering the question of counteractions and simultaneous use of intervention pricing, the resultant spot price under intervention pricing would only differ from the dispatch outcome if counteractions were ineffective, i.e. not equal. Therefore we believe the calculation of an intervention price by the dispatch engine should continue to accurately reflect pricing outcomes where counteractions are not effectively managed by the market operator.

One issue that could be considered as part of this review would be to consider where counteractions are implemented on units in the same region and same generation portfolio(s) as directed participant(s) should continue to qualify as an affected participant(s) for the purpose of affected participant compensation when pricing outcomes remain less than the compensation price paid to the directed participant for energy generated under direction. We question if this should this be considered as the participant(s) being paid twice via directed participant compensation and affected participant compensation for the same energy output.

The Paper notes the convening of the IPWG by AEMO to review AEMO's concerns regarding intervention pricing outcomes and the report prepared by AEMO's consultants SW Advisory and Endgame Economics. Following consideration of AEMO's concerns and the consultant's report, the IPWG rejected the report's recommendations. Whilst the Paper notes that at that time of the first IPWG meeting only eight system strength directions over 21 days had been issued in South Australia, the Paper fails to reflect that this matter was reconsidered and discussed at length at other subsequent IPWG workshops by which time a significant number of additional intervention events for system strength in South Australia had occurred. Members of the IPWG continued to reject the recommendations pending completion of a review of AEMO's current intervention pricing calculation methodology.

The Paper also indicates that AEMO has raised concerns that:

> *"higher what-if prices signal a need for more generation and this could result in more wind generation which could worsen the system strength situation".*[6]

This statement is of concern in that AEMO's own asynchronous generation output dispatch constraints would prevent this outcome. Asynchronous generation output would not be allowed to increase above the level supported by the number of synchronous generators in-service at any given time.

The Paper also fails to note that IPWG members raised and discussed the frequency and duration of interventions based solely on the minimum asynchronous generation threshold of 1,200 MW and requested in numerous meetings that additional thresholds below 1,200 MW be made available by AEMO in a timely manner to reduce the need for what were considered as potentially unnecessary interventions.

The IPWG through the course of their work conducted a "deep dive" review into AEMO's then current intervention pricing methodology. This review identified a number of issues in AEMO's methodology and developed and recommended a number of amendments to remove these errors. To date only one of these amendments to the methodology have been implemented with two other recommendations pending implementation. These errors had resulted in a number of significant intervention pricing outcome discrepancies impacting a number of regions.

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[6] Page 57, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

In our view, the Commission should consider that it was not intervention pricing per se that led to these erroneous outcomes, but the lack of transparency regarding the actual methodology adopted by AEMO for its implementation. It should also be noted that following the identification of errors in AEMO's then current intervention pricing methodology and the finalisation of recommendations to remove these errors, the IPWG reconsidered and confirmed their rejection of recommendations contained in AEMO's consultant's report.

The Paper provides information regarding the impact on pricing outcomes of intervention pricing in the 2018 calendar year period. This data contains the impacts of intervention pricing for both exercise of RERT contracts, for which the use of intervention pricing is undoubtedly warranted, and for system strength directions in South Australia. The data also includes outcomes from erroneous pricing outcomes due to errors in AEMO's then methodology and also fails to include for observable market responses by participants to prices below efficient dispatch, such as where renewable generators rebid from close to or at the Market Floor Price to the negative value of renewable energy certificates in response to forecasts of very low negative prices. We believe a more accurate comparison for the purpose of discussion under this review would be an analysis which compares pricing outcomes for system strength directions only, excluding those erroneous price outcomes due to the identified errors in AEMO's intervention pricing methodology and initial dispatch run price outcomes floored at levels of observed market withdrawal of renewable energy generators.

The paper also considers if the use of intervention pricing following exercise of RERT contracts should be discontinued and replaced by manual implementation of the Market Price Cap (MPC) similar to that imposed following involuntary load shedding. We do not support this change. RERT contracts are generally dispatched by the market operator to maintain system reserve levels as opposed to reduce the impact of involuntary load shedding. As such, market spot price outcomes would not be expected to be at the MPC. At times of RERT dispatch, significant generation may remain undispatched and not qualify for affected participant compensation, yet could be required to satisfy difference payments on financial contracts. As an example, on 30 November 2017, at the times of RERT dispatch in Victoria AEMO's market data indicated over 1,000 MW of generation capacity in Victoria and South Australia remained available but undispatched. Most of this generation would have been disadvantaged had the spot price been automatically set at the MPC following the exercise of RERT contracts instead of the prevailing intervention pricing outcomes of $80 to $300.

Generators placed in this position due to the implementation of the manual MPC override following exercise of RERT contracts would invariably review their financial contracting risk profile and respond to minimise their risk exposure to market intervention which would negatively impact contracting volumes in the NEM resulting in increased costs to consumers. It is also worth noting that this proposed changed was discussed at length by the IPWG and rejected as being an unwarranted market distortion.

There is a complementary issue to the question of intervention pricing that we believe warrants consideration as part of this review. We believe an underlying reason for the issue of directions is the failure under the rules to allow compensation to a generation resource that is constrained-on via the use of a dispatch constraint. Clause 3.9.7 sets out that a generator constrained-on for any reason is not entitled to receive compensation from the market's settlement process where the generating unit is dispatched below its offer price. We believe it is this failure under the Rules to pay "fair" compensation payments to a generation resource that is constrained-on that is the major contributing factor in generators bidding unavailable and awaiting issue of a direction by the market operator. This underlying cause of the requirement for AEMO to issue a Direction could be removed by allowing similar compensation provisions to that for a directed participant to also apply to any generation resource that is constrained-on below its offer price. In this case the constrained-on compensation framework would be based on the lower of the generating unit's offer price or the directions compensation framework with additional costs continued to be recovered from consumers. We believe that overall costs would be lower than that imposed by the directions compensation framework due to the normal competitive nature of market bids and offers.

The regional reference node test – rules clause 3.9.3 (d)

The regional reference node test (RRN test) is currently applied to determine if intervention pricing is to apply following the issue of a Direction by the market operator. The RRN test is not applied when a RERT contract is exercised. The IPWG noted that a RERT contract may also be exercised for power system security services at a remote location similar to how a Direction may be issued for which a Direction would not pass the RRN test. The IPWG recommended that AEMO submit a rule change request to apply the RRN test to determine if intervention pricing should apply following exercise of a RERT contract. ERM Power supports this area of AEMO's proposed rule change.

In considering the proposed rule change to clarify the wording of the RRN test, the Commission reviewed a number of historical applications of the test and considers that it is somewhat unclear that the test has been correctly applied on all occasions. In considering the application of the RRN test, it is our view that the test does not necessarily require alignment with an actual physical generating unit, or in the case of exercise of a RERT contract, a physical load. Nor should the test require demonstration of "scarcity" in either the supply of energy of FCAS referred to in the Paper as supply of a "service traded in the market".[7]

ERM Power submits that it is not a question of what power system service is required, but rather the question is that if, by supplying the service required by the market intervention, accurate market outcomes are distorted by the supply of additional energy, FCAS dispatch or the reduction in load consumed than would otherwise be the case absent the market intervention, the RRN test could be met. This was the original intent of the intervention (what-if) pricing rule.

We believe the existing rule, the AEMO proposed rule change and the AEMC's proposed alternative to alter the rule to adopt a test that reflects the economic rationale for intervention pricing,[8] all fail to meet the original intent of the intervention (what-if) pricing rule which was to remove any distortion to market outcomes arising for market intervention.

We submit that the RRN test could be clearly defined based on the original intent of the intervention (what-if) pricing rule based on the following principles:

- AEMO is satisfied that the need for the AEMO intervention event could be met by the issue of a direction or the exercise of a RERT contract for any power system service to a notional generating unit or load located at the RRN; and,
- which for the purpose of the rule has the assumed ability to supply the required power system service; and
- this results in either a change in energy or ancillary services dispatch or a reduction in energy consumed than would otherwise be the case absent the market intervention.

If the answer to these conditions is affirmed, in that the required service could be met by a notional generator or load at the RRN, and this changes market outcomes from that which would otherwise prevail, absent the market intervention, the RRN test would satisfied and intervention pricing would apply.

The replacement of the "plant at the regional reference node" as contained in the current rules with a "notional generating unit or load" removes any requirement for AEMO to determine the location of actual physical plant in relation to the RRN for the purpose of the Test. This improves the clarity of the rule on the basis of that which we believe is the critical question, "<u>could</u> a unit or load located at the RRN supply the required service(s)".

[7] Page 84, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper
[8] Pages 84 & 84, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

The Test should be technology neutral, however, for application of the Test assumes that the notional unit or load is capable of supply the required service(s), this also focuses clarity of the purpose of the Test to determine, "could a unit or load located at the RRN supply the required service(s)".

The final principle considers if the market intervention results in a change in market outcomes, such as pricing, dispatch volumes, etc, than would otherwise be the case absent the market intervention. If the market intervention results in no change to market outcomes, then application of intervention pricing is not required.

We believe the above principles if implemented in the Rules would provide greater clarity to the market operator for application of the RRN test than the current Rules, AEMO's proposed rule change and the AEMC's alternative rule changes while removing the need to determine if an actual physical plant is located at the RRN. It would also provide clarity regarding the actual application of the RRN test to the examples included in the Paper as follows.

In the examples detailed in *5.3.1 - Directions to northern Queensland generators on 13 October 2015; 5.3.3 - 1 December 2016: Direction to Mortlake power station; and 5.3.4 - 28-29 March 2017: Directions to Mt Stuart power station,* it is clear that the conditions for the definition of the RRN test as set out above would not be met as a Direction or the exercise of a RERT contract for any power system service to a notional unit or load located at the RRN would not have satisfied the power system service requirement at the time of market intervention.

In considering the example detailed in *5.3.21 - December 2016: directions to multiple parties in SA*, the issue of the Direction to Torrens Island A1 to provide an additional 10 MW of contingency raise fast FCAS would pass the RRN test as a notional generating unit at the RRN could also have supplied that power system service. The Direction to Pelican Point to reduce output to reduce the requirement for contingency raise fast FCAS would not pass the RRN test as in this case, it is only a reduction in output at Pelican Point, the South Australian generator with the highest output at the time of market intervention, that could provide the required power system service. The Instruction to Olympic Dam to reduce consumption to reduce the requirement for contingency lower fast FCAS would not pass the RRN test as in this case, it is only a reduction in consumption at Olympic Dam the largest load in South Australia at the time of market intervention, that could provide the required power system service. In the Paper, the Commission is incorrect in stating that the required reduction in contingency fast FCAS could have been met by "reducing generation and/or consumption anywhere in the network (so long as there are no network constraints in place)".[9] In the case of contingency services it can only be met by a reduction in output on the generator with the highest output or a reduction in consumption by the largest load at the time the market intervention is required.

The RRN test would not be met for both the reduction in output at Pelican Point and the reduction in consumption at Olympic Dam to relieve a deficit in the supply of contingency fast FCAS in South Australia due to supply scarcity. Yet, it does raise the question regarding an application of a new provision of similar intent to clause 3.9.2 (e)(1) for energy spot price determination to the determination of FCAS prices where the market operator has intervened due to FCAS scarcity. In the case of these two market interventions, we believe the Rules should require that the local prices in South Australia for the both contingency fast FCAS should have been set to the MPC due to the supply scarcity prevailing at the time of the market interventions. This would communicate the supply scarcity to other services providers and facilitate a response for the provision of additional FCAS to satisfy the required power system services and result in an outcome where the market intervention could be revoked.

With regards to examples detailed in *5.3.5 - Reliability events on 9 February and 1 March 2017; 5.3.6 - System strength directions in SA; and 5.3.7 - System security directions issued in Victoria in November 2018*, the power system service requirements for all three examples could clearly be met by a notional generating unit at the RRN and as such intervention pricing would apply.

[9] Page 70, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

The compensation framework

ERM Power supports "fair" compensation to any party who is financially disadvantaged by the invoking of market intervention. We also consider that no party should receive a "windfall" gain due to market intervention. For this reason, we support the proposed rule change to replace the words "$5,000 per "intervention price trading interval" with "$5,000 per "AEMO intervention event" in the rule clauses as set out in AEMO's rule change request.

Currently a participant could incur costs of $240,000 or receive a windfall gain of $240,000 for every full trading day where a market intervention was invoked. We do not believe this meets the plain English definition of what would be considered as "fair".

Also, as noted by the Commission:

> *"The variable application of the compensation threshold raises a number of issues, including consistency as between the determinations of independent experts, and consistency as between the approach adopted by independent experts and AEMO".*[10]

We believe that replacement of the $5,000 per intervention price trading interval requirement will improve clarity regarding the intent of the Rules requirement and remove the observed inconsistency in approach between the various independent experts and AEMO. We also support changes that the Rules clearly set out the basis for recovering affected participant compensation costs following RERT activations.

As noted in the Paper, there is currently limited transparency regarding the costs of compensation arising from a market intervention event. We believe increased transparency in this area is warranted, with additional details regarding the total of payments made to directed parties, the total of payments made to affected participants and the total of payments received from affected participants disclosed in the market intervention report prepared by AEMO. We do not believe that reporting of payments on an individual participant basis is required and would present an unnecessary administrative burden for AEMO. In addition, the market intervention report should detail the recovery of any costs from market customers on a regional basis.

The Paper raises the issue of the continuation of compensation payments to affected participants whose dispatch is impacted by market intervention, noting that currently a participant whose dispatch outcome is impacted by a network constraint receives no compensation.[11] In the case of a network constraint, an individual participant's impact on network congestion is transparent and a participant can, by their actions, seek to mitigate the impact of the constraint on generating unit output, whereas a participant has at best limited ability to mitigate the risk of market intervention.

The Paper also questions whether replacing the current $5,000 per intervention price trading interval provision with the proposed $5,000 per AEMO intervention event provision and if the current affected participants compensation framework could incentivise a non-directed generation participant to seek to increase their potential affected participant compensation amount by rebidding volume to higher priced bid bands.[12] In considering this issue, it should be recognised that a generator that rebids volume to higher priced bands runs the risk that the unit would not be dispatched under either the dispatch or intervention pricing run and as such no affected participant compensation would be payable. Also, by continuing to apply the $5,000 per intervention price trading interval threshold to affected participants, a participant that achieved a "windfall" benefit, would not be required to repay this "windfall" benefit as noted in the Paper's recent example of the review by Synergies Economic Consulting of a dispute by CS Energy of the amount it was required to pay to AEMO under the affected participant provisions.[13]

[10] Page 97, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper
[11] Page 101, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper
[12] Page 110, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper
[13] Page 92, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

In considering the question raised regarding continuing compensation to affected participants, where a participant's dispatch outcomes are distorted by market intervention, we believe "fair" compensation to a financially disadvantaged party remains warranted. To not do so would to expose participants to a "financial risk" over which they have no control. This risk is completely subject to the action of an independent party, in this case the market operator, which may leave them subject to a shortfall in spot revenue used to fund difference payments against their financial contracts. This would then flow through to assessment of additional dispatch risk for participants' contracting levels and ultimately increased costs to consumers.

As noted already, we believe participants should not receive a "windfall" gain due to market intervention. We consider that the negative impact on the normal operation of the market where market intervention is imposed by the market operator should be minimised where reasonably achievable.

The Paper also raises the issue of the level of compensation payable to a directed participant under the direction compensation framework, in particular, if the use of the 90th percentile of spot prices is sustainable over the long term and if the market suspension compensation framework would provide a more "fair" basis for compensation.[14] The Paper notes that participants will request that AEMO cancel an invoked Direction when spot prices increase above their marginal costs of production and then indicate that a participant will indicate an intention to remove a generating unit from service when the pre-dispatch forecast indicates that spot prices are expected to fall below marginal costs for a sustained period.[15] We consider these outcomes would be in-line with the normal functioning of an efficient market. As such we see no observable evidence that compensation in the form of the 90th percentile of spot prices is resulting in perverse incentives for directed generators.

On the question of replacing the current directed participant compensation framework with the market suspension compensation framework, there are a number of significant costs not included in the implemented automatic compensation methodology that we believe by their omission will result in an increased need for claims for additional compensation. This will result in an increased administrative burden for AEMO and participants, than would have otherwise been the case had these costs been included in the automatic compensation provisions, particularly if the invoking of market suspension pricing events were to increase.

Whilst we note the Commission's concerns that over time the 90th percentile of spot prices may be insufficient to cover a participant's "fair" costs, simply replacing the existing directions compensation framework, or implementing what is in effect a "constrained-on" compensation framework based on the market suspension compensation framework, will in our view, only increase the need for the lodgment of additional claims for compensation by participants unless modified to take into account other costs which are reasonably incurred.

Although we support a change to clause 3.9.7 to compensate generation in the event it is constrained-on, the compensation framework for this should result in a "fair" level of compensation which covers all incurred costs and not lead to an increase in the administrative burden for AEMO and participants.

Currently, AEMO issues a public Market Notice which informs the Market that an intervention event has been declared from a specific date/time. AEMO also issues a further public Market Notice which informs the Market that an intervention event has ceased from a specific date/time. AEMO includes these start and finish dates and times in its market intervention event reports. Provided that the Rules require that the duration of the intervention event to be used in the calculation of any compensation or payment to AEMO amounts is aligned with these public Market Notices, we see no reason for additional transparency or clarity in this area.

[14] Page 104, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

[15] Page 106, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

Frameworks for managing minimum levels of system strength and inertia

In Section 7, the Paper considers the market efficiency and additional cost impact of system strength shortfalls in South Australia, and AEMO's management of the issue via the use of Directions for this power system service. In considering this issue we believe that the Commission should have regards to:

- The determination that a system strength shortfall existed in South Australia was declared on 13 September 2017
- Directions for the provision of system strength services commenced from 25 April 2017.
- The new minimum system strength framework including the "do no harm" provision for new connecting generation and load has only been in effect in South Australia from mid-October 2017 and in the other NEM regions from 1 July 2018.
- Similar to the new minimum system strength framework, the framework for managing the rate of change of power system frequency has only been in effect from 1 July 2018.
- AEMO's System Strength Requirements Methodology was only published in July 2018.
- AEMO's Integrated System Plan (ISP) will also consider minimum system strength requirements through its modelling scenarios. The inaugural 2018 ISP and accompanying National Transmission Network Development Plan (NTNDP) has forecast that minimum system strength issues may emerge in a number of electrical sub-regions over the forecast timeframe. It is expected that the 2019 ISP will review and expand in this area.
- The new generator notice of closure rule requires that a synchronous generator must provide a minimum of 42 months' notice to AEMO prior to closure. This will provide a significant increase in closure notice to that supplied for Northern Power Station in South Australia.

In effect, the issues surrounding the system strength issues in South Australia arose with little notification to the Market, including AEMO, market participants and network service providers (NSPs). Since then, additional frameworks have been put in place and forward looking analysis has commenced to identify potential power system services issues in other regions such that the frequency and duration of Directions for system strength services which occurred in South Australia are unlikely to be repeated in other regions of the NEM. It should also be noted that Directions for system strength services are currently expected to decline following the commissioning of the initial two high-inertia synchronous condensers in South Australia in mid-2020.

In considering changes to the current intervention frameworks, we urge the Commission to consider the relatively recent changes implemented after the emergence of issues regarding the provision of power system services in South Australia and allow the benefits of these changes to transpire before recommending any significant additional changes as part of this review.

In considering the question of identifying power system services shortfalls up to 5 years in advance, we support the Commission's view that an initial preliminary notice of a potential shortfall should be issued. This would allow the relevant NSP to commence initial analysis of the most efficient response to the potential shortfall and should, in our view, also allow the commencement of the regulatory approval process as a contingent project for a range of preferred remediation options. In the event that AEMO declares a power system services shortfall at a later date, the pre-completion of analysis of the range of potential remediation options, including the regulatory approval process, as a contingent project for the range of potential options, would allow the NSP to move within a short timeframe to the procurement phase for the preferred remediation option. In the event that the identified power system services shortfall emerges more quickly than identified by AEMO, or that transient or variable shortfalls occur for limited time periods, Directions for the provision of power system services as identified in the Paper would remain both a flexible viable interim or ongoing solution to address the potential various shortfall conditions.

As indicated in the Paper:

> *"the relevant TNSP must make a range and level of system strength services available such that it is reasonably likely that these services are continuously available to meet the shortfall (taking into account the risk of unplanned outages, planned outages and the potential for system security services to impact typical patterns of dispatched generation)".*[16]

In considering the preferred options, such as additional synchronous condensers, to remove a potential short-term power system services shortfall arising as a result of planned or unplanned outages of network infrastructure, we support the use of Directions for the provision of power system services shortfalls if this results in the least cost option to consumers, as opposed to the construction of additional regulated network infrastructure.

Conclusion

ERM Power believes that the existing intervention pricing framework in general remains fit for purpose and superior to other solutions canvassed in the Paper. The original intent of the intervention (what-if) pricing rule was to remove any distortion to market outcomes arising for market intervention, it is our belief that this is a sound economic principle and one that should be continued. We support AEMO's view that the RRN test – clause 3.9.3(d) requires rewording to improve it clarity. ERM Power has included in this submission what we believe are clear principles on which any revised clause should be based. We support AEMO's rule change to apply the RRN test to market interventions where RERT contracts are exercised.

ERM Power supports the continued provision of "fair" compensation to parties financially disadvantaged by any market intervention event, similarly we support that no party should receive a "windfall" gain due to any intervention event. For this reason we support AEMO's rule change to alter the threshold for compensation or repayment to AEMO of any "windfall" gain from an "intervention price trading interval" basis to an "AEMO intervention event".

We believe that the Rules must ensure clear regulatory responsibilities for AEMO for both the timing and the extent (size and duration) of market intervention. Given the changing nature of supply including the increasing level of distributed energy resources, greater clarity regarding the use of market intervention and the reporting requirements for any market intervention should be considered. We consider that the review of the reporting requirements associated with market intervention is warranted and the reporting requirements should more closely mirror the amended RERT reporting requirements. It should be clearly demonstrable that market intervention is only imposed as a last resort and only to the extent necessary to manage prevailing power system conditions.

The Commission, through a number of rules changes, which have been in effect for less than 12 months has significantly altered the NEM frameworks for the timely provision of various power system services. In considering changes to the current intervention frameworks, we urge the Commission to consider these relatively recent changes implemented after the emergence of issues regarding the provision of power system services in South Australia and allow the benefits of these recent changes to transpire before recommending any significant additional changes as part of this review.

In considering any changes regarding the intervention pricing framework or associated compensation provisions as canvassed in the Consultation Paper, we believe that the Commission needs to consider that changes in these areas may not just impact the physical markets, but may have significant negative impacts on the financial contracts markets through changes to spot markets settlement risks to participants.

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

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[16] Page 146, Investigation into intervention mechanisms and system strength in the NEM Consultation Paper

Yours sincerely,

[signed]

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