ERM Power Generation Pty Ltd
Level 52, 111 Eagle Street
Brisbane QLD 4000
ABN 44 117 443 035
+61 7 3020 5100
ermpower.com.au

Friday, 26 April 2019

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

Dear Mr Pierce

EPR0073 Co-ordination of Generation and Transmission Investment Implementation - Access and Charging Review

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (the Commission) Co-ordination of Generation and Transmission Investment (CoGaTI) Implementation - Access and Charging Review Consultation Paper (the Paper) issued 1 March 2019 and the Supplementary Information Paper issued 4 April 2019.

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 critical that any changes to generator network access and charging arrangements result in not only improvements in efficiency of physical market dispatch and locational signals for potential generation development, but also ensure that proposed changes do not disrupt the financial contracts markets which provide the essential risk management framework for generation development to provide ongoing least cost reliability of supply to consumers.

The COGaTI Review Stage II – Implementation of changed generator Access and Charging Arrangements primarily seeks to introduce nodal pricing for generators, which the Paper refers to as "dynamic regional pricing", whilst retaining regional pricing for load and introduce a mechanism for generators, or potentially a large load, to fund network augmentation in return for receiving a financial transmission right (FTR) which under most but not all market conditions, reflects the difference between the generators nodal price and the regional reference price (RRP).

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

Whilst the paper refers to this FTR as a “firm” transmission right, we believe this terminology is incorrect as this “firm” right would not prevail under all potential network conditions and a generator would remain subject to basis risk between its nodal price and the RRP under a number of market conditions. This increased basis risk would be reflected in both the pricing and the level of volume offered for financial contracts to the market and would in our view invariably result in the increased costs of supply to consumers.

Phased approach to access reforms

Should the Commission recommend to Council of Australian Governments (CoAG) and CoAG accept the recommendation that the proposed COGaTI changed generator Access and Charging arrangements be implemented, ERM Power supports a phased approach to any reforms in the area of generator network access and charging arrangements, however, we are concerned that the proposed timeframe sets a date for adoption of generator nodal pricing with a yet to be finalised form of non-firm “grandfathered” FTR by July 2022 followed by the ability for generators to fund network augmentation by July 2023.

At best we estimate that this would result in delivered non consumer funded network augmentation from July 2026, based on a timeframe of 3 years to plan and construct any major network augmentation. We strongly oppose this proposed delay in the ability to fund network augmentation in return for FTR’s by 12 months following the introduction of generator nodal pricing. It is our view that this option should be introduced prior to the implementation of the proposed generator nodal pricing change and should be introduced as soon as achievable. If this change were to be introduced by December 2020, then network augmentation in return for FTR’s could result in network augmentation commissioned by January 2023.

We believe one of the key issues currently preventing generators funding of network augmentation is the lack of allocation of property rights for that section of the network for which the generator provides funding. ERM Power acknowledges the volume of new intermittent output generation seeking to connect to the network and the multiple issues associated with facilitating their connection, including the key question of who should pay the significant costs of network augmentation required to facilitate their connection. We support the Commission’s view set out in the Paper that funding of network augmentation to connect this new generation should not necessarily be underwritten by consumers.

The other key issue as raised in our previous submissions to the CoGaTI review process has been the lack of central coordination of data regarding network connection enquiries and accurate and regularly updated public information regarding the level of uncongested headroom across various sections of the network. We note the suggested improvements in this area submitted by the Australian Energy Council in the form of the proposed Transparency of New Projects rule change and recent improvements in the provision of data by AEMO.

Dynamic Regional Pricing

Whilst the Paper refers to “dynamic regional pricing”, in effect the outcome from implementing this change would be the introduction of generator nodal pricing into the NEM. At times of network congestion, remotely located generation on the “upstream” side of the network constraint would receive their calculated nodal price rather than the RRP. This introduces a new level of basis risk for both price and volume for generators.

Whilst the Paper proposes the introduction of a form of financial transmission right (FTR) to mitigate this basis risk, this FTR may provide only partial financial compensation, particularly at times of a network outage where the level of overall network access is reduced and generator network access may also be subject to variation based on the output of generators not subject to the same nodal pricing outcomes. A generator that is a positive “gatekeeper” for network congestion may not be incentivised by the prevailing RRP or its nodal price to increase output where this may be beneficial to other generators which are impacted by network congestion.

The Paper proposes that generators which are connected by a yet to specified date, would receive a form of dynamically calculated "grandfathered" FTR, to partially compensate generators for the difference between the generator's nodal price and the RRP, we support the allocation of "grandfathered" FTR's to existing generators. In calculating the level of dynamically calculated FTR, we believe the allocation must be based on the real time reported capability of the generator. For scheduled generators this would be the bid reported maximum availability, for semi-scheduled generators it would be AEMO's unconstrained intermittent generation forecast, applicable to that dispatch interval. This would ensure that a generator is not allocated FTR compensation for capacity that is unable to be physically supplied to the market.

ERM Power also believes that to provide an accurate locational signal for new generators, new generators would not receive any "allocated" or "grandfathered" FTR unless spare capacity currently existed on the shared network, and only up to the level of spare access on the shared network, or the new generator paid for network augmentation to provide the required level of network access, including the maintenance of access for existing generation. The extent of any proposed augmentation to achieve access for a new generator or improve the level of the dynamically calculated FTR for an existing generator to the RRP must include for all required network augmentation to ensure financial access the RRN, not just to connect or improve connection to the shared network. The allocation of a FTR should not appropriate capacity from the shared network to the detriment of existing generation.

We believe the Commission must clearly articulate the methodology for allocation of the dynamically calculated FTR with regards to network sections where remote local generation interacts with a regulated interconnector(s). Currently due to the choice of constraint equation formulation[3], and the leverage impact of allocating very low constraint equation co-efficients to interconnectors, where the dispatch calculation may reduce an interconnector limit by thirteen Megawatts (MW) in preference to reducing the output from a remote local generator by one MW, output from remote local generation can displace lower settled cost generation from another region. This outcome results in negative value inter-regional settlement resides, often referred to as counterprice flows, which are ultimately paid for by consumers. The Commission needs to clarify if the dynamically calculated FTR will be based on a nominal interconnector flow of zero MW, at the time of network congestion, which would remove the accumulation of negative resides, or alternatively, would an interconnector also be entitled to a share of the FTR payment based on the nominal interconnector capacity. This has critical implications for the level of volume offered for future contracting periods to the financial contracts market, as either outcome increases the basis risk for remote local generation compared to current.

ERM Power recommends the Commission consider in greater detail potential FTR payments to a positive "gatekeeper" generator. A positive "gatekeeper" generator is a generator that by increasing output would increase network transfer capacity. By way of example, where additional output from the positive "gatekeeper" could increase interconnector flows from a lower priced region to the benefit of consumers in the importing region, the "gatekeeper" generator could be paid the loss adjusted importing region's RRP as opposed its own RRP, this could be facilitated by the allocation of the additional settlements residues created by the increased flows to the "gatekeeper" generator rather than Settlement Residue Auction unit holders.

We support the Commissions view that allowing transmission connected large scale storage to access the nodal price for energy storage would provide improved signals to the storage system and increase overall market efficiency.

We support continued settlement at the RRP for all other load located within a region.

[3] The currently used Option 4 constraint formulation compares the loss adjusted RRP of the adjacent region to the bid price of the local remote generator ignoring the fact that the local remote generator will be settled at the RRP.

We understand the Commission is considering if AEMO's annually calculated transmission system marginal loss factors should be included as a factor in the calculation of the generator nodal price or should remain as per current as a volume reduction in the settlement process. In so far that either method would in settlement terms yield the same outcome we see no reason to potentially increase the complexity of the process by moving away from the current well understood process.

If however the Commission is considering moving away from the current AEMO annually calculated transmission system marginal loss factors to a dynamic real time transmission system marginal losses calculation, we would urge extreme caution in considering this change as this would add significant complexity to the settlement process and the formulation of dispatch offers by generators and negatively impact the level of volume offered by generators in the financial contracts markets due to the increased uncertainly of the price which a generator will be paid. Whilst the current process delivers a degree of variability on a year to year basis, outcomes within each financial year are static and provide certainty of outcome to generators for that financial year as to the adjusted level of volume that will be settled at the Regional Reference Node. Whilst it is acknowledged that the current process generally results in over recovery of transmission losses, improvements in this area would occur if AEMO's demand and energy forecasts were less conservative and more reflective of potential actual outcomes as the forward calculated forecast system losses increase with higher forecast system demand.

Information from dynamic regional pricing

In the Paper the Commission has proposed an interim step between the implementation of generator nodal price and FTR's and the implementation of generator funding of transmission investment. Given the level of detail which could be available from improvements in demand forecasting and modelling methodology and the level of existing information regarding transmission network capability which could be more transparently made available to the market through improvements in education provision, potentially by AEMO, we would like to better understand from the Commission what additional benefits could be derived from Phase 2 of the proposed implementation program. We remain of the opinion that the provision of increased transparency of information from AEMO and a more centrally coordinated approach to generator connection enquiries is a key requirement going forward and will provide the necessary information to better coordinate generation and network investment.

Generator funding of transmission investment

ERM Power would support a rule change that would introduce into the National Electricity Rules, (the Rules) provisions which would allow the allocation of an explicit tradeable property right to a generator in return for funding network investment. We believe this will correct a long standing deficiency in the current Rules where another party may appropriate, at no cost, a property right funded by the original generator. We believe this change should be the first step in any proposed change to the current Rules.

We also agree with the Commission's view that the lack of a transparent and accurate locational signal to new generation developers is leading to inefficient investment in new generation resources which will ultimately result in increased costs to consumers. We believe this outcome may be being supported by provisions within the Regulatory Investment Test for Transmission (RIT-T) which allows Network Service Providers (NSP's) to claim benefits for transmission investment to connect generators for the sole purpose of meeting legislated targets regardless of physical location or efficiency of costs to consumers, in effect a view by developers that "if I build here, transmission paid for by consumers will come", we agree with the Commission's view that the risk of such inefficient investment should not be underwritten by consumers.

As indicated earlier in this submission, the extent of any proposed augmentation to achieve access for a new generator or improve the level of the dynamically calculated FTR for an existing generator to the RRP must include for all required network augmentation to ensure financial access the RRN.

Where a Network Service Provider receives a payment from a new or existing generator for a network augmentation to facilitate allocation of a new or increased FTR, this must require completion of a physical network augmentation by the NSP. The NSP can't simply receive an access payment from a generator for allocation of existing network capacity.

We believe that any proposed rule changes must clearly define what constitutes a generator funded network augmentation and how any resulting property right should be calculated and allocated. There may be significant potential in the NEM to increase network transfer capability by the use of generator runback or tripping schemes to better utilise AEMO's N-1 operation of network capacity, or generator funding of real time monitoring of wind speed and ambient temperature of a network corridor to allow the use of dynamic line ratings. It is our view that a generator who offers such runback or tripping schemes or funds network corridor monitoring which results in improvements in network transfer capability should be allocated the increased FTR's following their implementation. This would incentivise the provision of such low cost network augmentation which would benefit consumers through more efficient use of the network. This could be facilitated in the settlements process with NSP's required to register all existing and future generator runback, tripping or other schemes and the level of increased benefit in network transfer capability with AEMO. This increased network capability could then be allocated to the service provider in calculating the real time FTR compensation. Absent this change to incentives, generators that would be capable of providing such services would be reluctant to incur the costs of doing so.

The Paper considers that proposed change to the Rules to allow generators to fund transmission augmentation in return for a tradeable property right should result in decreased overall costs to consumers. One area worth further consideration by the Commission in this regards is the question whether such network augmentation should be undertaken under a regulated or non-regulated regime by an NSP. Undertaking generator funded network augmentation under a non-regulated regime may result in increased costs for consumers as the total cost of generator and network access could be higher than under the regulated network investment case. The new generator(s) would still fund the cost of any regulated network augmentation under this model.

The Paper considers that FTR's would be non-firm based on network capability at the time of congestion and proposes that NSP be incentivised by a penalty payment scheme to undertake maintenance outages at times where network transfer requirements may be lower. We believe in order for this to be effective, the penalty payments would need to be a sufficient value, potentially higher than all the combined existing NSP incentive schemes, and payable to FTR holders.

We also believe the other area requiring rule changes in the network maintenance planning area is in relation to a minimum notice period for planned network outages. We believe the Rules should mandate a minimum notice period for submission of a planned network outage to AEMO for inclusion in the Network Outage Schedule of 90 to 120 days with an appropriate penalty for non-compliance. Currently, AEMO reporting indicates that the majority of planned network outages would be entered into the NOS with less than 90 days' notice. This lack of adequate notification of planned network outages prevents efficient risk management by participants and is a factor considered in the volume of financial contracts offered.

Inter-Regional TUOS

The Paper sets out potential changes to the current inter-regional transmission use of system (TUOS) charging regime on the basis that the current methodology fails to adequately allocate costs of network augmentation within a region which benefits consumers in an adjacent region. We agree with the Commission's concerns in this regard. The proposed New South Wales (NSW) to South Australia "Riverlink" interconnector will primarily require network augmentation in NSW whilst the majority of the benefit will accrue to consumers in South Australia. We question the current allocation of costs particularly given that existing network congestion between Wagga and the load centers of NSW will prevent generation from South Australia suppling NSW consumers at times when NSW consumers would value this generation.

Where the benefit can be clearly demonstrated to accrue in another region, the Rules should allocate the costs of the network augmentation in proportion to where the benefit accrues. This should be calculated on a sufficiently granular basis such that the overall “market” benefit is captured, as opposed to a simple net flows calculation.

Conclusion

ERM Power supports the Commissions ongoing review of the key issues of generator network access, the provision of improved locational signals to potential generation projects and who should underwrite the significant costs that will be incurred to connect new generation projects, much of which is planned to be located remote to the existing transmission network. ERM Power is very supportive of the Commission’s view that consumers should not necessarily be required to underwrite this as regulated network investment.

We remain concerned that insufficient educational support is provided to the market such that intending generators have clear information regarding network access, the risk of congestion and the purpose of and calculation of network loss factors and the impact of these on generator revenues.

We believe Phase 1 of any rule changes should be the allocation of an explicit tradeable property right to a generator in return for funding network investment, any proposed rule changes in this area must clearly define what constitutes a generator funded network augmentation and how any resulting property right should be calculated and allocated   ERM Power believes this will correct a long standing deficiency in the current Rules.

We support changes to the Rules in the area of inter-regional TUOS charging to ensure that those who benefit from a regulated network investment are allocated the costs of this network investment. This may not necessarily be limited to consumers, particularly when longer circuitous interconnector routes are selected to enable lower connection costs for generator connection.

ERM Power is concerned by the Commission’s proposal to introduce generator nodal pricing and FTR’s to the NEM. We believe greater consideration is required by the Commission regarding the impact of such a significant change on the financial contracts market particularly given the need for compliance with the qualifying contract provisions and market liquidity obligations under the proposed Retailer Reliability Obligation. Significantly more detail is required from the Commission with regards to the calculation methodology for “grandfathered” FTR’s, in particular were an interconnector forms part of a network flow path subject to network congestion. Based on the level of information currently provided, ERM Power is unable to support the introduction of generator nodal pricing and FTR’s to the NEM.

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

Yours sincerely,

[signed]

David Guiver

Executive General Manager - Trading

07 3020 5137 – dguiver@ermpower.com.au