AUSTRALIAN ENERGY REGULATOR

Our Ref: D19/170447
Your Ref: EPR0073
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12 November 2019

Mr John Pierce AO
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Dear Mr Pierce

**Renewable Energy Zones Discussion Paper**

Thank you for the opportunity to comment on the Australian Energy Market Commission's (AEMC) 'Coordination of Generation and Transmission Investment – Access Reform' (CoGaTI) discussion paper on facilitating renewable energy zones (REZs).

We welcome the clarity the AEMC provides in this discussion paper in distinguishing the types of REZs. However, we have a number of questions and concerns about the AEMC's characterisation of issues in facilitating type B REZs and its proposed model for facilitating type B REZs.

**Types of REZs**

We support the AEMC's characterisation of type A and B REZs, with greenfield and brownfield variants. We consider clarifying the distinction between type A and type B REZs is important in:

(a) determining who benefits from the assets, and

(b) as such, who should pay for the assets.

For completeness, we note that, under type B REZs, the shared transmission network should not necessarily be built to connect all generators in the REZ. The shared transmission network should be built only as far as is efficient from the perspective of cost benefit analysis (CBA) performed within the central transmission planning process. Any assets constructed past this "point" are connection assets to facilitate generators' connection to the shared transmission network. These connection assets do not provide prescribed transmission services and so are not funded by consumers.

**Characterisation of the issues**

We agree with the AEMC's characterisation of the first issue: 'Incentives to coordinate generation infrastructure'. We also agree that these are related to type A REZs and are largely commercially-driven issues that are outside the scope of the regulatory framework.

We are, however, open to learning about potential improvements to the regulatory framework that may promote coordination of generation infrastructure.

On the second issue ‘Incentives to coordinate transmission and generation infrastructure’, we recognise generators have little incentive to use the funded augmentation mechanism in the current framework because:

- generators cannot exclude other generators using their funded augmentation for free (through a property or financial ‘right’ to the capacity)
- if generators know an investment project will pass a regulatory investment test for transmission (RIT-T), it will likely be funded by consumers and there is no incentive to provide a contribution.

We also recognise there is added complexity to this issue. Under a meshed electricity network, investments that are privately profitable are not necessarily efficient from market-wide perspective. This is, in part, because funded augmentations made by individual generators can affect the business cases of other generators connected to the network.

On the third issue, ‘Incentives for efficient transmission infrastructure’, we consider that the current transmission planning process provides for efficient transmission investment.[1] More specifically, we consider if a transmission investment project does not pass the RIT-T cost benefit analysis, then it is not efficient. That is, it does not maximise the present value of net economic benefit to all those who produce, consume and transport electricity in the market. It may provide benefits to individual generators (i.e. privately profitable), but this does not necessarily result in efficiency from a market-wide perspective.

In describing the third problem, the AEMC states ‘there are no incentives to undertake speculative investment in new transmission infrastructure to build out to new generation areas because the costs may not be recovered’.[2] It then defines speculative investment as ‘investments which have not been provided for in the allowed revenue as part of the AER’s revenue determination, or otherwise provided for through, for example, the contingent project process.’

We consider all investment decisions contain risk as they are ex-ante decisions based on forecasts, and TNSPs and their investors determine the projects they are willing to take based on their risk-return profile and our revenue allowance. Our revenue allowances do not dictate the specific projects TNSPs are expected to undertake. However, we consider that projects that do not pass a RIT-T should not be included in revenue allowances and passed through to customers. This is because they are not efficient from a market-wide perspective.

In our view, the third issue is better characterised as managing the risk of inefficient investment in the shared transmission network.[3] This risk is present for all transmission investments under any transmission planning process. However, this risk is particularly pertinent in the current context of the energy market transition, as generation is now driving

[1] The transmission planning process (with the actionable ISP) will contain the planned investments (including regulatory investment tests for transmission (RIT-Ts)) outlined in transmission annual planning reports (TAPRs) developed by transmission network service providers (TNSPs) for shorter term more targeted planning, and a biennial integrated system plan (ISP) developed by AEMO for long term strategic network planning across the NEM. TNSPs (or RIT proponents) apply RIT-Ts to individual transmission investment projects. We note that under the current NER, there is no direct link between the RIT-T and the subsequent investment or operational decision that the TNSP may make, nor funding or revenue for that investment. TNSPs’ revenue allowances are determined through the AER’s periodic revenue determination process under the incentive based regulatory framework.

[2] AEMC, REZ discussion paper, October 2014, pp. 22-23, 43.

[3] The risk of over-building can be otherwise characterised as the risk of stranded assets.

the benefits of transmission investment to a greater extent than before (i.e. under historical central planning of both network and large scale centralised thermal generation investment), particularly with regard to REZs. As such, transmission projects that connect REZs are built on the expectation that forecast generation will eventuate. There may be mechanisms to manage the risk of such generation not eventuating, as consumers fully bear this risk. Examples of such mechanisms include Energy Networks Australia's (ENA's) model set out in the AEMC's discussion paper. We expand on this issue below.

**Addressing the Type B REZ issues**

<u>Issue 2: Incentives to coordinate transmission and generation infrastructure</u>

If generators are seeking shared transmission network investment outcomes that fall outside the central planning processes, and are prepared to fund the entirety of such investment, then the funded augmentation mechanism may be a solution worth exploring. At a conceptual level, this mechanism could be paired with long-term financial hedges (e.g. Financial Transmission Rights (FTRs)). Although FTRs will not provide generators with the physical right to dispatch, FTR-holders will nevertheless receive financial access to the regional price in the form of FTR payouts, despite co-location of subsequent generators.[4] The "dispatch problem" would be addressed by the introduction of FTRs under the AEMC's proposed access reform model.[5]

However, as noted above, there are complexities in allowing private investment in the shared transmission network. We consider the AEMC would need to evaluate the potential for consumers to face indirect costs. For example, due to potential inefficient market impacts (i.e. if the private investment affects other generators' business cases) or operation and maintenance costs not being sufficiently recovered from the relevant generator(s).

If this flexibility is something that generators seek, we consider they provide specific examples of private investments in the shared network they are unable to undertake. This would allow the AEMC and stakeholders to better consider an appropriate solution.

<u>Issue 3: Managing the risk of inefficient investment in the shared transmission network, which sits with consumers</u>

We support exploring mechanisms that allow generators to firm up their commitment to connect to new shared transmission infrastructure at the integrated system plan (ISP) or RIT-T stage, in order to improve the modelling under these central planning processes and mitigate the risk of inefficient investment (e.g. stranded assets). We see value in exploring ENA's model from this perspective, as it allows generators to express their interest and effectively pay a refundable 'deposit' to secure access to a long term financial hedge across the new capacity once built. We recognise there are challenges to work through. For example, determining the size of the 'deposit' required to encourage genuine expressions of interest. Further, the difference in timelines for the planning and construction of transmission projects versus generation projects means that generators/developers may not be in a position to indicate any commitment to connect at the ISP or RIT-T stage.

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[4] We note that due to the lumpy nature of transmission investment, other participants may benefit from the additional capacity that the first generator has funded. However, generators may be accepting of this provided they obtain the revenue certainty that they are after.

[5] See AEMC, 'CoGaTI Proposed Access Model Discussion Paper' (14 October 2019).

Nevertheless, we consider that there are significant benefits associated with investigating models that mitigate the risk of inefficient transmission investment in REZs. We note that, notwithstanding the central planning process, there is likely to be significant uncertainty associated with the location of generation investments within REZs and that some generation investments may be highly speculative. As such, there is merit in investigating measures that seek to mitigate the risk that consumers will bear the costs of unnecessary transmission investment and which seek to transfer some of this risk onto the parties best placed to manage these risks, namely generators themselves.

We do not support the AEMC's proposed changes to the RIT-T. We consider any transmission network investment that consumers fund should have a net economic benefit to all those who produce, consume and transport electricity in the market. Funds that move between market participants (for example, from generators to TNSPs) count as a wealth transfer and should not affect the calculation of the net economic benefit under the RIT-T.[6]

In addition, we seek more clarity on the AEMC's proposed REZ model, as it is unclear how it would work together with the AEMC's proposed access model, and where it is and is not consistent with the ENA's proposed model. For example, it is unclear how revenue adequacy could be met if long term hedges and FTRs are both paid out using settlement residue, and if long term hedges and FTRs were purchased on the same transmission capacity. We also caution against linking the price of long term financial hedging instruments to the cost of underlying physical transmission infrastructure. This is because the price of financial hedging instruments are determined by buyers' valuation of expected future cash flows, and these are linked to differences in wholesale electricity prices, not the cost of transmission investment.

We thank the AEMC for the opportunity to submit on this proposal and look forward to the outcomes of the CoGaTI implementation work program. If you have any questions about our submission, please feel free to contact Arista Kontos (08 8213 3492).

Yours sincerely

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Chair
Australian Energy Regulator

[6] See RIT-T application guidelines, pp. 61-62.