8/11/2019

Jess Boddington
Australian Energy Market Commission (AEMC)
Level 6, 201 Elizabeth Street
NSW 2000

Via electronic lodgement

Dear Jess,

**Re – COGATI Discussion Papers on Proposed Access Model and Renewable Energy Zones: EPR0073**

Mondo appreciates the opportunity to comment on the AEMC's Coordination of generation and transmission investment (COGATI) two Discussion Paper on the Proposed Access Model and Renewable Energy Zones (REZ).

Mondo provides a variety of contracted transmission and distribution services, including grid connections for new generators, battery energy storage systems and aggregation of distributed energy resources.

**General comments**

The proposals to introduce dynamic regional pricing and financial transmission rights (FTRs) have the potential to provide improved risk management opportunities for scheduled participants in the National Electricity Market (NEM), and to also provide opportunities for improved coordination of generator and network investment. Although the potential for improvement has been well articulated in the AEMC discussion paper, this should be considered cautiously given the ongoing energy transformation and the many challenges being imposed on the NEM.

It would be easier to support the proposed reforms in an environment where generation technology was stable, operational demand growth was relatively predictable, energy policy was well articulated and government interventions were rare. Unfortunately, none of the above criteria apply at present, and as a consequence, NEM and energy policy in general should be assessed first and foremost, for its ability to navigate the challenging energy transformation environment that we are currently experiencing. In some cases, it may be possible to envisage energy policy that is able to both support the energy transformation as well as then providing a stable platform for ongoing efficiencies once we emerge from the transformation. It is quite difficult however, to anticipate with any degree of confidence, how the energy sector will look once we have travelled through the transformation process.

For these reasons, whilst Mondo is generally supportive of the measures being proposed, our fear is that these reforms may be rendered ineffective during the transition phase by the numerous policy uncertainties and interventions that characterise our current environment. At the same time, it is very clear that action to improve network access for new generation in more remote parts of the network is imperative, and needs to be actioned with some urgency.

Given the uncertainty outlined above regarding the potential for the proposed reforms to provide rapid improvements to generator and network coordination, it is suggested that an alternative set of arrangements are put in place to deal with the specific and interim (during the transition) issues that we currently face. Such a solution may require a more centralised planning approach, perhaps being built on the current Integrated System Plan (ISP) and the Energy Security Board (ESB) initiatives to “action the ISP”.

It is noted that the AEMC’s preferred option for supporting REZs is to introduce long term hedges to fund transmission assets. These arrangements would allow a generator to purchase a long-term hedge that provides a form of firmer access to the regional reference price through a financial payment. Whilst potentially providing incentives for generators to provide funding in support of new network investment, these changes ultimately rely on the dynamic regional pricing mechanism to be in place, and so will require some time for development and implementation.

Whilst these initiatives may eventually support network coordination and investment, there remains concern that a more immediate fix is needed to support the new generation required during the energy transformation in the coming years. This could be in the form of an interim arrangement, which would ultimately be replaced by the proposals in the discussion papers.

Mondo has proposed an interim solution to the REZ issue, which does not rely on dynamic regional pricing. This proposal (priority constraints) is discussed in this submission in response to discussion paper two, and is suggested as an interim option to more immediately facilitate transmission investment.

As noted earlier, once we have managed to substantially navigate through the energy transformation, more refined market reforms such as those proposed in the discussion paper are likely to provide an ongoing benefit, and would therefore be supported.

Further to the above overarching comments, Mondo provides the following specific comments on some of the matters raised in the discussion paper.

**Discussion paper one - Access Model**

Discussion paper number one proposes changing the wholesale electricity pricing regime in the NEM from the current single price per region, to one where there would be separate prices at every transmission node where scheduled or semi-scheduled participants (such as generators and storage) are connected. Each of these transmission node prices would be referred to as the Local Marginal Price

(LMP). All demand in a region would be settled at the regional reference price (RRP), which would be calculated as a volume weighted average of all LMPs in the region.

Exposing scheduled and semi-scheduled participants to the LMP rather than the RRP is expected to provide greater incentives for participants to bid competitively under all circumstances, including when impacted by network constraints.

The other main element being proposed as part of the access model is to introduce FTRs, which would allow participants to hedge the difference in price between an LMP and the RRP, either in their region, or another region. This is expected to provide a more effective risk management tool for participants to manage financial risks associated with network congestion.

Although there are many important details yet to be finalised, these significant reforms are expected to deliver efficiency improvements to the NEM, reduce barriers to new generator entrants, and improve the coordination of generator and network investment. Implementing these reforms will need to be carried out carefully to ensure a good fit with the unique elements of the Australian NEM. This will require some time, as there are many important details to consider. It will also be very important that reforms such as this are tightly coordinated with the work being coordinated by the ESB to consider the appropriate NEM design post the year 2025.

One important question to consider is whether significant reforms such as these should be introduced in advance of the ESB post2025 outcomes, or whether these should be delayed until they can be efficiently included within the ESB post-2025 work stream. The post 2025 NEM review will provide a holistic market review, which is likely to result in a more effective, and administratively efficient, outcome than if we are to assess critical issues individually.

Many stakeholders agree that there is a need for urgent reform to overcome the existing impediments to network and generator development in remote areas, and this is clearly (and understandably) a key driver behind the AEMC's thinking in proposing these reforms. .

However, on balance Mondo is inclined towards the view that these useful reforms should be carefully considered and developed over time, with a view to introducing them as part of the post-2025 market review (assuming that the post-2025 market design lends itself to such mechanisms).

Specific comments on some elements of the proposed reforms are set out below.

Section 3.2.4 of the discussion paper notes that under an FTR regime, "financial outcomes would be decoupled from physical dispatch". Whilst it is clear how this statement derives from the proposal to link FTRs to a strike volume rather than a dispatch outcome, careful consideration needs to be given to the implications of this approach. We should question whether this is really a good thing. If it is important to ensure that efficient dispatch is driven by the market signals, then decoupling financial outcomes from dispatch would seem to run counter to this objective.

Section 5.7 of the discussion paper notes that the AEMC's preference is to design financial transmission right instruments that allow market participants to hedge the risk of price differences across the network that arise from network losses. The discussion paper then notes that the detail of how this will be implemented is yet to be determined.

Mondo's view is that the additional complexity and uncertainty that would be introduced by such a step is not justified. The key focus should be on resolving the congestion issues, which will be significantly complex in itself, without adding in losses as well. The additional benefit from including losses seems to be quite small, yet it will substantially increase the design and implementation complexity.

Section 4.6.3 of the discussion paper proposes two alternative measures that could be introduced to pre-emptively mitigate against potential market power manipulation. It seems a failing of a proposed market design that it should feel a need to build in market failure mechanisms. Furthermore, building a market failure mechanism in advance of the market failure manifesting has the distinct potential to incorrectly anticipate the nature of the market power event, and therefore, devise inappropriate response mechanisms. The NEM has grappled with various questions of market power since its inception, and the NEM governance structures and institutions have developed and matured to provide rigorous monitoring and response mechanisms should they be needed (e.g. AER & ACCC). Pre-emptive market power response mechanisms should not be pursued.

Section 5.2.2 of the discussion paper outlines the relative merits of options vs swaps in the context of FTRs. We agree that FTRs should be based on put options for generators and call options for load, as this will prevent participants having to pay in the event that the local price is above (for generators) or below (for loads) the regional price. As noted by the AEMC, the use of swaps would give rise to both positive and negative payments, and would therefore not meet the risk management objectives which would be important to the FTRs serving their purpose.

The proposals set out in section 5.3.2 regarding FTRs between regional prices are supported, since this is likely to improve firmness of inter-regional hedging options. As noted in the discussion paper, the current settlement residue auctions (SRAs) have not been successful in supporting inter regional hedging and this has undermined the liquidity of hedging more generally.

Section 5.4 of the discussion paper considers alternative arrangements for when FTRs should payout on the price difference. Alternatives considered include continuous rights (active all of the time), time of use rights (active only for pre-defined times), weather dependent (for example, active only during strong wind conditions), or correlated with generation output. The AEMC have proposed not to implement bespoke FTR options that would more closely match a generators output, due to their additional complexity.

Whilst complexity may discourage some participants, there should nevertheless be an option available for participants to purchase an FTR that exactly matches its generation output. This would allow these participants to overcome the disadvantages of over/under hedging as identified in the discussion paper. Ultimately, there should be flexibility available to participants and TNSPs to jointly create FTR products that suit their needs, and this need not be mandated or constrained by the policy design. Further, there is no reason why intermediaries might not develop products which better meet the needs of generators through secondary markets.

**Discussion paper two – Renewable Energy Zones**

The key proposal in discussion paper two is to provide the opportunity for generators to contribute to specific network investments by purchasing a transmission hedge, which would provide the generator with greater confidence that their network investment would not be able to be compromised by other ‘free rider’ generators. The underpinning mechanism of the proposal in discussion paper two is the long term hedge that would be available for generators to purchase. As noted earlier in this submission, the long term hedge mechanism would only be effective under the regime of dynamic regional pricing and FTRs, as outlined in discussion paper one. This dependency needs to be explicitly acknowledged so that it is clear that a pre-requisite for the proposals in discussion paper two is that the reforms outlined in discussion paper one are implemented.

The reforms outlined in discussion paper two are less well developed than those in discussion paper one, and therefore require additional consideration before they can be fully supported. Mondo does recognise that with careful consideration and design, and provided that the NEM design continues to be suitable, the proposed reforms to REZs have the potential to be beneficial in assisting with the coordination of long-term generator and network investments. However, again noting the uncertainties and externalities previously outlined, the likelihood of these reforms being rapidly implemented, adopted by developers and resulting in much needed transmission investment over the short to medium term remains doubtful.

For this reason, Mondo favours the proposals outlined in discussion paper two being carefully considered in the context of the post-2025 market design, rather than being implemented in a rushed time frame. In the interim, the focus for the transition period should be on effective actioning of the ISP including prioritisation of the REZs.

Section 3.5.3 of discussion paper number two notes that the main barrier to facilitating a type B REZ is the lack of incentives for generators to fund shared network assets due to the so called free rider problem. Mondo believes that the free rider problem can be alleviated relatively easily through an interim measure that could be implemented quite quickly. Such a measure could assist during the transition period and then be replaced by the more rigorous transmission hedging arrangements in the post-2025 arrangements.

The interim measure, which avoids the need to introduce dynamic regional pricing and new transmission hedging instruments, would be to implement “dispatch priority constraints” for generators that fund network development. A generator that holds a dispatch priority constraint position would only be constrained down if there were no other alternative. In other words, it would be given dispatch priority over other generators in its vicinity. Constraints of this type would be able to be formulated by AEMO using the current NEMDE constraint formulation. The only change needed would be for the new constraint status to be recognised in the NEM rules, and thus AEMO provided with the regulatory authority to give nominated generators dispatch priority.

Mondo hopes that the comments contained in this submission are of assistance to the AEMC in its deliberations on this consultation. Please do not hesitate to contact me either by email or on 03 9695 6061 if you have any further inquiries.

Yours sincerely

**Margarida Pimentel**

**Manager Policy and Aggregation Services**