2/08/2019

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

Via electronic lodgement

Dear Jess,

Coordination of generation and transmission investment – access reform (EPR0073)

Mondo appreciates the opportunity to comment on the AEMC's directions paper into the coordination of generation and transmission investment (COGATI) implementation – access and charging (Directions paper).

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.

The directions paper has proposed a new generator access and charging regime which would introduce dynamic local regional pricing and a new hedging product based on intra-regional price differences. The directions paper also touches on potential reforms aimed at improving coordination of generator and network planning, as well as supporting renewable energy zones. These latter issues are outlined in fairly high level in the directions paper, with further work foreshadowed to examine the detail.

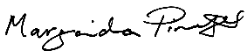
Mondo is broadly supportive of reforms aimed at improving coordination of generator and transmission investment. Furthermore, Mondo can see merit in the dynamic regional pricing and hedging proposals outlined in the directions paper, although we also believe that further detailed modelling and analysis should be carried out before any decision is taken to proceed. As acknowledged in the directions paper, the proposals for linking transmission hedging with transmission planning are still lacking in detail, and will need further exploration before drawing any conclusions. Mondo notes that this work is raising many of the issues that were examined in the Transmission Frameworks Review[1] (completed April 2013), which also grappled with mechanisms for transmission access and charging. Mondo suggests that some of the detailed work undertaken in the transmission frameworks review should be re-examined in the context of this COGATI review.

A key concern held by Mondo relates to the need to carefully coordinate this work with other key reforms currently underway such as the Energy Security Board's (ESB) Post 2025 Market Design review and other initiatives by AEMO. We must avoid introducing fundamental reforms prior to 2025 unless it is absolutely clear that such reforms will be maintained by, and are consistent with, any further reforms coming out of the ESB Post 2025 Market Design review.

Attachment 1 contains detailed responses from Mondo to many of the proposals and questions in the directions paper.

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

[1] See AEMC website at https://www.aemc.gov.au/markets-reviews-advice/transmission-frameworks-review

Attachment 1 - Mondo response to AEMC COGATI Access Reform

For ease of reference, Mondo has provided responses in this submission to the key issues and questions raised in the AEMC COGATI Access and Charging Directions Paper. The headings in this submission below refer to the relevant sections contained in the directions paper.

Dynamic Regional Pricing

Dynamic regional pricing would introduce price signals to generators that better reflect the marginal cost of supplying electricity from that generator's local node within the transmission network.

Design of dynamic regional pricing

Mondo is broadly supportive of the proposed dynamic regional pricing proposal, subject to consideration of further details. The proposal to make scheduled generators, scheduled loads and scheduled storage subject to the price at their local transmission node has the potential to overcome many of the issues associated with disorderly bidding, improve transparency of the costs of congestion, and improve locational signals for investment.

Whilst Mondo can see merit in this proposal and the closely related introduction of transmission hedges (discussed below), Mondo believes that before a fundamental reform such as this is introduced into the NEM, there needs to be very careful examination of the numerous details of how this would be implemented. Once the details have been finalised, there should then be a substantial trial period which provides a sandbox environment in which the simulated results of dynamic regional pricing are presented, and which also allows stakeholders to respond to the simulated results through dummy bids. Without a market trial in a sandbox environment, it is very difficult for anyone to have confidence on how these reforms might unfold in the context of the NEM.

One particular clarification that will need to be addressed is how dynamic regional pricing would treat loss factors, particularly in light of current rule change proposals to potentially move to dynamic loss factors. In our submission to the AEMC's most recent Transmission Loss Factor Rule change consultation, Mondo has argued against introducing dynamic loss factors as they will introduce an additional volatile parameter which would expose participants to additional risk.

Under a dynamic regional pricing arrangement, it could be argued that loss factors should then also be calculated dynamically. Mondo remains sceptical about the merit of this approach, since any potential benefit due to more accurate dynamic loss factors might be small in comparison to the costs of additional complexity and increased volatility. Again, Mondo believes that the potential impact of this should be examined in a trial environment.

Allocation of settlement residues

Transmission hedges are proposed as a means for generators to manage their price risk when the local price falls below the reference node price. Mondo agrees with the proposition that transmission hedges should be implemented at the same time as dynamic regional pricing. To do otherwise would introduce a new price risk for generators with no means to manage that risk.

Noting that there remain several details about how transmission hedges would be defined and structured, the basic proposal is that a generator would purchase a hedge quantity (in MW), and would then be paid a settlement amount equal to the hedge quantity multiplied by the price difference between its local node and the regional reference node. If the transmission hedge quantity is different to the physical flow, then settlement will not balance. In cases where the physical flow is less than the hedge quantity, there will be excess settlement residues. On the other hand, when the physical flow is greater than the hedge quantity, then the settlement residue will be less than required to fully pay out the hedged participants, and some form of scaling back will be necessary.

In consideration of the three options presented in the directions paper, Mondo does not support option A (surplus allocated to generators without transmission hedges) as this would diminish the value of the transmission hedges and provide an incentive for generators to remain unhedged.

Since the money paid by generators for hedges will be used to offset the TUOS cost to customers, it seems reasonable that if a surplus of money is raised in settlement due to the physical flow exceeding the generator hedge amount, then the surplus should be returned to customers via the relevant TNSP (option B).

Option C (surplus supports fund to increase the firmness of transmission hedges) appears to have some merit, as the firmness of the transmission hedges will be important in achieving success. It is difficult to properly understand how this option might work in practice, and so we would need to see further detail on how it would be applied.

Scope of Dynamic Regional Pricing

The directions paper suggests that:

- all scheduled and semi-scheduled participants (generation, load and storage) would face their local marginal price;
- all non-scheduled participants (load and generation) would face the regional reference price; and
- parties would not be able to opt in or out of facing a locational marginal price other than by becoming scheduled.

Mondo is broadly supportive of the proposed approach as it applies the local marginal price to those parties with the greatest incentive and ability to respond to the price volatility – namely scheduled participants.

We note the suggestion in the directions paper that under the proposed approach, non-scheduled generators may have an incentive to become scheduled to enable them to achieve a better outcome. If this is the case, Mondo would consider this to be a positive outcome as increasing the number of scheduled generators provides AEMO with better ability to manage power system security.

As noted in the directions paper, since most regional load would be located at or close to each regional reference node, the difference between the local and regional reference prices for loads is unlikely to be significant. In any case, it would be more difficult for loads to respond to price signals than generators. For these reasons, Mondo supports the proposal that all non-scheduled loads would face the regional reference price.

The proposal that virtual power plants (VPP) should face the regional reference price rather than the local marginal price is also supported as an initial step. As noted by the AEMC, if the VPP were to face its local marginal price, there would be a need to separate out the VPP and load components at the customer, retailer and transmission-node levels. This would likely lead to higher cost and complexity. Mondo would suggest however, that as the volume of VPPs becomes a more integral component of the NEM landscape, this decision could be reviewed to understand whether encouraging VPPs to face their local marginal price could lead to improved overall efficiencies and consistency with generators and battery storage.

Choice of regional price

For those participants that continue to be settled at the regional reference price, the directions paper asks whether the current regional reference price should be used, or whether an alternative price, such as a volume weighted average of all local prices in the region should be used.

Mondo favours what appears to be the simplest option, which is to use the current regional reference price for settlement of all non-scheduled loads and generation, as discussed above. The alternative of using some form of volume weighted average of all other local prices in the region to determine a ‘load aggregation price’ would introduce new pricing arrangements into the NEM. Such changes would have significant implications in a number of areas including calculation of hedging prices, settlement residue and forward contracting.

On balance, Mondo favours retaining the regional reference price, but remains open to further consideration of the cost / benefit of an alternative load aggregation price approach.

Treatment of losses

Mondo has provided a detailed response to the AEMC’s Transmission Loss Factor Rule change consultation which discusses, amongst other things, potential movement to dynamic loss factors. As we have set out in that submission, we believe it is not yet apparent that the increased complexity and volatility of dynamic loss factors is justified. It is our view that dynamic regional pricing could be implemented based on the current yearly static marginal loss factor methodology.

Whether the potential benefits of moving to dynamic loss factors under a dynamic regional pricing arrangement would lead to greater efficiencies is difficult to gauge. Mondo would suggest that if dynamic regional pricing is to be implemented, then it should at least initially be based on the existing loss factor methodology to reduce the number of elements that are changing. If after some years of experience, it then becomes clear that a change to dynamic loss factors is warranted, this could then be pursued.

Transmission hedging

Transmission hedging would allow generators to manage the price risk they face at times when there is congestion within the network. As stated earlier, Mondo is of the view that if dynamic regional pricing is introduced in the NEM, then it will be important that transmission hedges are made available at the same time to ensure that generators have a means to manage the new price risk that they would face.

Transmission planning

Under the proposed access model, the sale of hedging products would fund and guide the development of new transmission assets both within regions and between regions. The collective sum of transmission hedges purchased would comprise a 'generator access standard' that AEMO and transmission network service providers would be required to plan the network to. Mondo notes that this proposal is similar to the planning standard concept that was contained in the AEMC’s Transmission Frameworks Review, which was concluded in April 2013.

Mondo is attracted to the idea of a transmission planning standard being informed by generator hedging decisions, but there is a great deal of detail that would need to be carefully considered before any commitment could be given.

Since the Transmission Framework Review considered similar questions in some detail, Mondo believes there would be value in re-visiting the proposals contained in that previous review to ascertain their suitability to the current proposals.

Hedging products - Amount

Mondo suggests that generators should not be able to purchase transmission hedges beyond their generation capability. This is to ensure that they are not incentivised to cause a constraint to bind and be ‘over-compensated” through excess constraint residue payments.

Hedging products - Location

Mondo suggest that initially, only intra-regional hedges should be offered, leaving the existing settlement residue auction product as a proxy for a fully formed inter-regional hedge. This approach is suggested as a means of staging the introduction of local marginal pricing and transmission hedging. Inter-regional hedging could be considered in a subsequent stage.

Hedging products - Duration

It is conceivable that generators and TNSPs will in different circumstances, see merit in either a short term (1-2 years) or a longer term (30-50 year) hedge agreement. As a general principle, Mondo would prefer that these decisions are largely left with the counter parties of the hedge agreement to decide, and not subject to regulation.

Secondary markets are likely to develop and these will in turn, influence counter parties in their decisions about agreement duration. However, the AEMC should not seek to impose any regulations to control secondary markets. These should be left to develop organically to maximise innovation and efficiency.

There may be some concern that transmission hedges will need to include certain items, and that in some cases, one of the counter parties may have access to more information than the other, placing one party at a disadvantage in the negotiation process. Such concerns could potentially be alleviated by having supporting documents and template agreements, similar to those currently provided by the Australian Financial Markets Association (AFMA) for over the counter agreements in the NEM.

Hedging products - Type

Similar to the comments above, the aim should be to impose as little regulatory constraint as possible on the type of hedging agreements that generators and TNSPs may choose to enter into.

One restriction that should be imposed is that they must meet certain requirements in terms of how they are implemented in AEMO's settlement system – this simply means that the hedge agreement must be able to be represented as a MW amount for each trading interval. This should not mean however, that the hedge must be a fixed MW quantity – but merely that for each given trading interval, the generator and the TNSP have agreed on how the MW quantity will be determined and expressed to AEMO.

Hedging products - Procurement

There are many questions to be considered in ensuring an efficient and effective procurement process, including:

- How would existing transmission capability be allocated and offered as hedges?
- If a generator purchases a hedge to reflect existing network capability, for what time period does the hedge and the TNSP planning standard obligation apply?
- If a generator seeks to purchase a hedge for additional network capability (beyond the existing network capability), what assurances does the generator have that this will be provided, and when does the generator need to provide funds for future network investment?
- If a generator seeks additional network capability and purchases a hedge, does this trigger a RIT-T process? If so, what if the RIT-T fails to be approved?
- What are the options for TNSPs to overbuild in anticipation of future hedging requests?

As noted earlier in this submission, many of the above questions were contemplated in the previous Transmission Frameworks Review, and Mondo would suggest that the AEMC review that work to gauge its application to the current review.

Hedging products – Pricing

The directions paper presents one option of applying a long run incremental cost (LRIC) method to establishing the price for transmission hedges. This method seeks to identify incremental network costs needed to accommodate a given generator hedge. In theory, this approach seems to be the most economically valid, but it would seem that its accuracy will be critically dependent on the assumptions made about future generator investment.

The directions paper provides only high level detail on the proposal making it difficult to assess. The LRIC concept was considered in the Transmission Framework Review referred to earlier, and it may be worthwhile for the AEMC to revisit some of the analysis and discussion raised in that consultation.

The directions paper also presents an alternative 'fair value' pricing proposal, which is equal to the long run forecast price difference between the local price and the regional reference price. This approach seeks to measure the value (to a generator) of the proposed network augmentation, rather than its costs. Presumably the investment would not proceed if the fair value identified is less than the TNSP's assessment of what a network augmentation would actually cost. Again, without further detail on how this mechanism would be implemented, it is difficult to provide a more comprehensive response.

Renewable Energy Zones

The directions paper includes discussion on options aimed at improving the coordination of generator and transmission investment in areas identified by AEMO as being valuable because of their abundance of wind and / or solar resources – renewable energy zones (REZ).

<u>Option one – TNSP 'open season'</u>

Under this option, the TNSP would establish an 'open season' period during which connection applications within a REZ would be accepted, but not processed. At the end of the period, the TNSP would then assess all applications received up to that point as a group.

This approach has some similarities to the existing scale efficient network extension (SENE), which has not been used since being introduced in the NEM. The AEMC should look into why SENEs have not been progressed as part of its consideration of the open season proposal.

There would need to be careful consideration of the time period across which the open season is maintained. Defining a period that is too short would likely mean that very few generators would be able to align their project implementation timetables to take advantage of the open season. Defining a period that is too long on the other hand, would mean that important network augmentations might be delayed unnecessarily.

Overall this option may be relatively easy to implement but may have limited success.

<u>*Option two* - Shared cost recovery mode</u>

Under this option, AEMO's Integrated System Plan would determine the prescribed 'efficient capacity' level for a REZ. The cost of investment in a REZ up to its prescribed efficient capacity level could be shared between consumers, generators and TNSPs. Capacity exceeding the efficient capacity level would be treated as speculative.

This options spreads the risk of investment across a number of different parties. Whilst sharing the risk has some appeal, it is not clear that the parties being allocated a share of the investment risk are well placed to manage those risks.

Implementation of this approach would be more complex than option one.

Alternative – Transmission Bonds

Mondo notes that the AEMC has previously decided not to support the transmission bonds idea first proposed by ENGIE. The key reasons given by the AEMC for not supporting this proposal appear to be that transmission bonds[2]:

- can only complement, not replace the RIT-T,
- would represent a departure from the NEM open access regime.

Mondo tends to agree with both of these observations, but suggests that they may not be sufficient reasons for rejecting the proposal.

In considering how the transmission hedges might influence transmission planning, the directions paper points towards these informing, rather than directing the planning process. This would seem to be similar to what the transmission bond proposal could achieve in informing the RIT-T.

The second criticism of the transmission bond proposal that it would undermine the open access principle in that generators who purchase transmission bonds would then expect to have “privileged connection rights to the REZ for a set period”. Mondo suggests that there may be alternative approaches to the ‘free rider’ issue that perhaps do not represent a fundamental departure from open access. For example, an alternative approach could be one where all generators have equal rights to connect to a REZ, but generators holding transmission bonds could be given priority access in dispatch. This could be achieved easily by AEMO re-arranging relevant constraint equations to give priority to bond holding generators, as shown in the following simplified example:

Typical constraint formulation: G1 + G2 < Rating

If G1 holds a transmission bond and G2 does not, this constraint equation could be re-formulated as follows:

G2 < Rating – G1

This would mean that the output of G2 will be reduced as a priority over reducing G1.

There are no doubt a range of alternative approaches to this issue. The key point is that there would appear to be alternative approaches that overcome the issues identified by the AEMC, which might be worthy of further consideration in support of transmission bonds.

[2] AEMC: Coordination of Generation and Transmission Investment Final Report – 21 December 2018, section 5.4.3.

Implementation timeframe

Mondo is concerned that it remains unclear how the proposed changes, which are fundamental reforms to the NEM, would fit within the ESB's Post 2025 Market Design review, also expected to introduce fundamental change. It is important to avoid having one set of fundamental changes now, and then another set of changes post 2025. Ideally, transmission access reforms should now be seen as a step towards the ESB's Post 2025 Market Design review outcomes. This would require close coordination across the AEMC and ESB processes.