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Australian Energy Market Commission
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Dear Ms Bowron

Coordination of Generation and Transmission Investment (CoGaTI) Implementation – Access and Charging

Meridian Energy Australia Pty Ltd and Powershop Australia Pty Ltd (MEA Group) thanks the Australian Energy Market Commission (AEMC) for the opportunity to provide comments in response to the Coordination of Generation and Transmission Investment (CoGaTI) Implementation – Access and Charging Consultation Paper (the Paper).

The MEA Group is a vertically integrated generator and retailer focused entirely on renewable generation. We opened our portfolio of generation assets with the Mt Mercer and Mt Millar wind farms and in early 2018 acquired the Hume, Burrinjuck and Keepit hydroelectric power stations, further expanding our modes of generation. We have also supplemented our asset portfolio by entering into a number of power purchase agreements with other renewable generators, and through this investment in new generation we have continued to support Australia's transition to renewable energy. Powershop has also been active in supporting community energy initiatives, including providing operational and market services for the community-owned Hepburn Wind Farm, supporting the Warburton hydro project, and funding a large range of community and social enterprise energy projects through our Your Community Energy program.

Powershop is an innovative retailer committed to providing lower prices for customers and which recognises the benefits to customers in transitioning to a more distributed and renewable-based energy system. Over the last five years, Powershop has introduced a number of significant, innovative and customer-centric initiatives into the Victorian market, including the first mobile app that allows customers to monitor their usage, a peer-to-peer solar trading trial and a successful customer-led demand response program.

The issues that the Paper has raised affect the industry as a whole, and they need to be properly resolved to ensure the continuing orderly transformation of the energy network. In this regard, the MEA Group would suggest that taking appropriate action with respect to the Integrated System Plan (ISP) will be crucial.

The MEA Group suggests that any reform should be properly coordinated, with sufficient time for all stakeholders to undertake a full assessment of the impacts and the potential interaction with other industry elements (e.g. financial markets, development impacts, security and reliability). Time should also be allocated to detailed studies and modelling, ideally undertaken by independent third parties. Further, any underlying assumptions and results should be robust, and ultimately any reform should demonstrate clear benefits for customers as well as meeting the National Electricity Objective (NEO).

Please find below our responses to the questions raised in the Paper.

PHASING OF ACCESS REFORMS

1. Is our proposed approach to phasing access reforms appropriate?

The proposal in the Paper to phase this particular reform is sensible and should allow for sufficient engagement with all stakeholders.

However, taking into account the totality of reform currently underway or proposed across the National Electricity Market (NEM), the MEA Group has concerns that this particular access and charging reform does not fully consider the ramifications of those other reforms currently underway. Specifically, the project to shift to five minute settlement and the Energy Security Board's (ESB) post-2025 market design program are likely to address some of the issues the charging and access reforms are proposed to address.

2. Are the number and nature of the phases appropriate? How might access reform be phased differently?

The MEA Group does not consider the AEMC's approach to phasing to be appropriate. The MEA Group suggests that Phase 1 should introduce measures that provide more information and a better understanding of the issues that the reform is attempting to address. This would enable development of a process that better aligns generation investment with transmission investment.

The MEA Group believes the existing Regulatory Investment Test for Transmission (RIT-T) process could be reformed to take into account lower costs to customers if all proposed generation is connected to a proposed transmission line. Such a reform would tie the costs associated with transmission to the prices customers pay for electricity.

The MEA Group does not agree with the proposed dynamic regional pricing proposal, and it is also unclear how reform to the inter-regional Transmission Use of System (IR-TUoS) pricing regime will ultimately benefit customers. It is difficult to comment on the phasing in of proposed reform in the absence of clear evidence of the benefits the reform is seeking to achieve, and whether other reforms might be able to achieve similar outcomes, with greater customer benefits.

3. What interactions with other market design reforms throughout the sector, and the energy transformation more generally, should be considered when developing and assessing transmission access reforms?

The market design reforms that are likely to have key interdependencies with the proposed charging and access reforms include:

- the ESB's Post 2025 Market Design for the NEM, which amongst other things will also consider options that may include more centralised planning and decision making;
- the change to a five minute settlement regime, which may positively impact disorderly bidding issues from July 2021 onward (the results of which cannot be known until the reform has been introduced);
- AEMO's Global Settlement project, scheduled for completion in February 2022 (with a soft release to align with the introduction of the five minute settlement regime in July 2021); and
- AEMO's rule change request to develop a stand-alone registration category for energy storage systems in the NEM (which AEMO is yet to submit).

The MEA Group notes that whilst the timelines for the above reforms currently appear on track, one or more could easily be delayed. The AEMC will be aware that such a delay has occurred in the rule change to implement the priority Group 1 Projects under the ISP (i.e. the South Australian Council of Social Service has disputed the conclusions in Project Energy Connect's Project Assessment Conclusions Report).

4. What should be taken into account when considering how to transition to these new arrangements?

The MEA Group would suggest that considerable stakeholder engagement is required prior to transitioning to new arrangements. Prior to or during this process more information will be required, in particular greater detail and clarity should be provided with respect to the benefits associated with dynamic regional pricing and the mechanisms associated with the purchase of firm access, and how asymmetrical information would be dealt with between generators and Transmission Network Service Providers (TNSP).

The MEA Group does not see the potential benefits from the proposed reform outweighing the associated risks, which include:

- the prospect of triggering change of law clauses under most existing power purchase agreements (dynamic regional pricing); and
- significantly impacting the ability of a generator to provide swaps and other financial derivatives to manage risk, as it would be almost impossible to price those products, with the possible outcome of higher prices for customers.

The MEA Group believes that the marginal loss factor (MLF) allocated to generators at their connection point is a clear identifier of locations in the transmission system that will not benefit from additional generation. Whilst it is currently sufficient, the MEA Group believes that the utility of the MLF as an identifier of generation suitability could be improved (based on current proposals for a quarterly rolling MLF). However, the MEA Group's view on this point may change if market rules are rapidly changed to address perceived shortcomings, making redundant the economic and financial lessons learned from current experiences.

PHASE 1: DYNAMIC REGIONAL PRICING

1. What is the nature of the risk on generators from being settled at the dynamic regional price in the event of congestion? To what extent is this risk different from (and greater or less than) the current risk to generators of being constrained off/down in the event of congestion? What impact may these changing risks have on the contract market, both in terms of products, liquidity, and risks businesses are exposed to?

There will be significant risks for generators being settled at the dynamic regional price, the majority of which are associated with the generator receiving a different and likely lower price for its production. Whilst some of these risks may potentially be offset by new market proposals (intra-regional settlement residue auction), they will not be fully offset because of the greater complexity they introduce.

These risks are greater than those under the current arrangement where dispatch (i.e. semi-dispatch cap) is set in relation to the capacity and price bid by a generator in any event. The only difference under the proposed reform is that these generators will receive a lower price during constraint periods.

2. Is generator capacity an appropriate metric on which to allocate the settlement residue which arises from dynamic regional pricing? If not, what alternative metric should be used? Which particular measure of capacity should be used (e.g. nameplate capacity, maximum output in previous X years)? How might the use of capacity or another metric create distorted incentives for generators and/or storage devices?

The MEA Group is unable to offer a considered opinion on this proposal based on the limited information released to date. However, we note that it may be the case that one form of capacity metric is appropriate for scheduled generators while another form is appropriate for semi-scheduled generators (e.g. unconstrained intermittent generation forecast).

3. Should storage, when importing from the grid, be settled at the dynamic regional price? What might the effects of this be?

The MEA Group is unable to offer a considered opinion on this proposal based on the limited information released to date. At a high level it would be sensible to incentivise storage projects to charge during periods of constraint to absorb the lower cost local generation, potentially alleviating some or all of the constraint.

4. What issues or unintended consequences might arise?

Under the proposed reform to transmission access we may see a scenario where transmission costs are higher in area A where there is a good wind/solar resource compared to lower transmission costs in area B where the wind/solar resource is fair. Consequently, generators will likely seek to build out the fair resource first (area B) before focusing on the better resource (area A) as the transmission costs are lower (notwithstanding generation from area A should be more economical due to a better resource). The MEA Group would suggest that this scenario may lead to higher costs for customers.

The MEA Group believes there is a significant risk that this reform is too heavily weighted in favour of those businesses that have the capacity to aggregate a number of potential generation sites and underwrite the transmission investment to secure firm access for those sites. The reforms will prioritise these sites ahead of smaller, potentially lower cost sites being developed by those without the financial or regulatory resources necessary to participate in this regime. Indeed, the MEA Group would query whether smaller capacity projects would continue to be economical under a firm access regime.

The transmission reform also places energy price risk on the TNSP (who is ultimately responsible for paying the difference between the dynamic regional price and regional nodal price) when they commit to provide firm access to a generator, for which the TNSP may not have sufficient experience in managing that risk.

It is also unclear as to how negotiations would take place with TNSPs under a firm access regime where there is a clear asymmetry of information between the TNSP and the generator. Potentially any such offers for firm access will be on a 'take it or leave it' basis.

Finally, it is also unclear whether in circumstances where access can be provided by any registered TNSP, the provision of firm access be subject to a competitive process between registered TNSPs.

5. What are the nature and extent of implementation costs, such as system changes (e.g. settlement reallocations), that would be required to implement phase 1?

At this stage, it is difficult to understand or quantify the extent of system changes required. Given the extensive reform currently underway across the entire sector, the MEA Group would encourage the AEMC to minimise the requirement for further system changes in order to avoid additional resources and ultimately higher costs for customers.

The system changes associated with the five minute settlement and global settlements projects are expected to continue for a further eighteen months. The likely changes associated with this reform will require similar resources within AEMO and the technology teams within each respective participant organisation.

INFORMATION FROM DYNAMIC REGIONAL PRICING

1. What information is likely to be revealed through dynamic regional pricing?

The MEA Group believes that dynamic regional pricing will provide an understanding of how the market as a whole views the combined impact of the network constraints of new and existing generation. This information, like most market-based information, will not be granular or capable of being separated into its various components. Consequently, we are uncertain if this reform will genuinely assist with information sharing, or provide any greater insights than the existing information provided by MLF's (or indeed the increased information that could be provided by an improved MLF regime).

2. How valuable is the information from dynamic regional pricing likely to be in the various transmission planning processes? Will it have other uses?

The value of this information is unclear. The only real information provided by the reforms will be historical market prices for constraint effects. All forecasts will be judgements only and each participant can have their own view of those forecasts. In practice, networks which will not be experienced or exposed to market participation will be forced to make estimates of future market values without the true capability to do so.

3. How should the information revealed by dynamic regional pricing be revealed to the market?

If dynamic regional pricing provides a genuine market signal then the information it provides will be revealed through pricing decisions made by each participant. It is unclear whether the proposal is an attempt to create a true market that would lead to genuine price discovery or some form of simulated market where a central decision maker is expected to determine the true price from this 'market' activity.

4. How might AEMO, TNSPs and the AER integrate the information into their processes?

In view of the limited development of this proposal, it is difficult to envisage the actual information to be generated and therefore how it might be usefully integrated into the electricity market processes by AEMO, TNSP's and the Australian Energy Regulator. However, if the proponents of this proposal do not know how to do this then it is difficult to comprehend the basis on which the proposal is being put forward, or how they or the AEMC are going to be able to demonstrate the benefits to customers, or how the proposal meets the NEO.

5. Should the rules be modified to require these parties to take this information into account, and if so, how?

Any proposed reform which intends to make major changes to core market principles at great risk to customers, the market and necessary investment, should be sufficiently developed and considered so that the information created by the reform is of sufficient value to counter or offset those risks and their attending costs. The proponents, and the AEMC, should ensure that any information discovered by this potentially high cost and high risk change ensures that the regulated and non-market exposed industry participants are required to make use of this information.

As we have indicated earlier, the MEA Group would suggest that there is currently insufficient information with respect to the proposal to form a cogent view as to whether it is necessary or the most preferable means of addressing the issues it is supposed to address. The proposal also fails also to advise how the benefits of reform would outweigh the significant associated costs and risks, or that sufficient useful information would be gained to assist in network and system planning.

Notwithstanding the above, if such reform was to be implemented the rules must include a requirement for regulated and non-market exposed industry participants to utilise all relevant information, disclosed and revealed.

GENERATORS FUND TRANSMISSION INVESTMENT

1. What issues and considerations should the AEMC take into account when developing and assessing phase 3?

The MEA Group do not consider that this proposal is sufficiently advanced to fully consider the proposed Phase 1. If there is to be a Phase 3 in the form proposed, or otherwise, such a phase should be developed and informed by the earlier phases alongside appropriate industry engagement, investigation and analysis.

ACCESS REFORM TIMEFRAMES

1. Are the timeframes suggested for the access reforms appropriate?

The MEA Group strongly believes the timeframes for the proposed reforms are inappropriate. This is a fundamental reform to the market that is likely to have significant, material implications. Insufficient time has been allocated to fully assess the proposal and allow for the discovery and assessment of all related implications and interactions with other changes in the market.

2. Is the timing of the phases appropriate?

As discussed above, we do not consider the content of the phases to be appropriately determined at this time, and their timing is equally requiring further thought.

The MEA Group has not responded to the final questions in relation to Transmission Use of Systems (TUoS) charging framework reforms and the IR-TUoS arrangements. We consider these components as part of the many complex issues that this reform raises that can only be fully analysed and assessed with the benefit of further information and a more detailed understanding of the reform, including analysis of how the market might respond to the proposal if implemented.

The MEA Group questions that the benefits associated with this complex proposal outweigh its associated costs and risks.

If you have any queries or would like to discuss any aspect of this submission please do not hesitate to contact me.

Yours sincerely,

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