22 April 2019

The Commissioners
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Sent to: AEMC by online lodgement

Dear Commissioners

Coordination of Generation and Transmission Investment
Access and Charging Consultation Paper
EPR 0073

Major Energy Users Inc (MEU) is pleased to provide its thoughts on the issues raised in the Consultation Paper for Coordination of Generation and Transmission Investment – access and charging.

The MEU was established by very large energy using firms to represent their interests in the energy markets. As most of the members are located regionally and are the largest employer in these regions, the MEU is required by its members to ensure that its views also accommodate the needs of their suppliers and employees in those regional areas. It is on this basis the MEU and its regional affiliates have been advocating in the interests of energy consumer for over 20 years and it has a high recognition as providing informed comment on energy issues from a consumer viewpoint with various regulators (ACCC, AEMO, AEMC, AER and regional regulators) and with governments.

The MEU stresses that the views expressed by the MEU in this response are based on looking at the issues from the perspective of consumers of electricity but it has not attempted to provide significant analysis on how the proposed changes might impact generators, TNSPs and other stakeholders.

In general, the MEU supports the thrust of the changes proposed by AEMC in that they provide a sensible approach to resolving the issue of congestion that has always been an intransigent problem in the transmission network since the NEM first commenced operation. The MEU view has consistently been (and it still believes) that the cost of

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providing the transmission system is better managed as a cost to generators rather than a cost to consumers.

The AEMC proposed approach starts to reflect the reality about sales of other commodities; where the seller includes the cost of delivery to its market of its product. The MEU notes that a move for generators to be able to fund the building of transmission assets to ensure they are not prevented from delivering their product to their market by the actions of other generators is a partial acceptance of the MEU view. In this regard, the MEU notes that this very issue of generators being able to fund transmission assets was debated at length in 2014 and 2015 when the AEMC looked to develop the Optional Firm Access (OFA) approach to allow generators to acquire firm access on the transmission network.

In its April 2015 response to the draft final report on the OFA (EPR 0039), the MEU commented:

> Overall, the MEU considers that the draft final report is very comprehensive and generally provides a workable process for the implementation of the OFA concept.

The MEU notes that in the discussion of the new approach proposed by the AEMC it expresses a view that the OFA as developed in 2015 is no longer applicable in the current NEM environment. While the MEU is not sure this is the case, it accepts the AEMC observation.

While generally supportive of the new approach, the MEU does have some concerns that should be addressed on the development of generators being able to get firm access on the transmission network.

1. Phased implementation and access reform timeline

The MEU notes that the AEMC observes in its consultation paper (page 6) that the OFA needs changing to match the current needs of the NEM. The MEU notes that if the environment that applies in the NEM now is sufficiently different to that applying just 4 years ago when the OFA was developed, this raises the question – should we be concerned that the new approach will similarly be superseded by the time generators are able to commence the process of implementation in July 2023?

With this in mind, the MEU considers that the ability to acquire firm access rights (FARs) needs to be implemented without delay. Already there are generators seeking to be connected to the grid who might be prepared to pay to achieve firm access.

The purpose for introducing “dynamic regional pricing” (DRP) is apparently a tool to identify where congestion might occur and the cost of such congestion causes the market but many generators already have a reasonably good idea of where congestion already occurs, the costs that congestion causes them and whether there would be benefits to them of obtaining firm access now. Even with the locating of new generation where the best resource is available, generators are aware that their decision might introduce congestion (or increase it) if they were to connect to the transmission network. Having the ability to address the issue of firm access now, might prevent an investment deferral or no investment at all.

While the MEU can see there are advantages in investigating the size, location and cost of any congestion, and the provision of the resultant information to the market, there seems no reason to delay the ability of generators from being able to buy firm access now if they so elect. The MEU is aware that some new generation assets have already implemented other actions (eg installing system strength assets in order to allow them to connect to the transmission network) so to allow them to buy FARs is just an extension of what they are already doing. Allowing implementation of being able to buy firm access as soon as possible will be a benefit to consumers as this has the potential to increase generator competition far earlier than by following the AEMC phased approach.

The MEU notes that even if generators sought to obtain FARs now, the time frame for transmission networks to be able to provide the service may take 2-3 years by the time needed assets are designed and installed, so by phasing the process as outlined in the consultation paper will mean that it will not be until 2025 or 2026 that the benefit of this change will be seen by consumers. This is just too long!

2. Dynamic regional pricing

The MEU supports the introduction of the dynamic regional pricing (DRP) approach as a tool to provide guidance as to the cost impact of congestion on the generators which are upstream of the congestion.

However, the MEU can see difficulties in the allocation of the residue between the generators being constrained. Noting that the congestion could occur at any time, the use of nameplate rating can be quite misleading, especially for intermittent generation. Renewable generators might have their output limited by environmental factors (eg wind falling, late afternoon when solar has a lower capacity, etc) and even a thermal generator might not be able to deliver its nameplate rating (eg high temperature when fuelled generators are less efficient, imposed derating, etc). With this in mind, the MEU considers that the ambient conditions at the time of the congestion have to be considered when allocating any residue.

Further, shot run costs of generation need to be considered as well. Even between thermal generators the difference in short run costs should be a factor. For example, if the congestion is caused by competing coal fired generators, why should an open cycle gas fired gas turbine located upstream of the congestion be eligible for any residue allocation when its costs are so much higher such that an efficient dispatch profile would have precluded its dispatch?

The MEU is very concerned as to how end users will be impacted, especially end users upstream of the congestion. In theory, as the DRP is a form of nodal pricing, those upstream end users should only be exposed to the DRP rather than the regional reference price (RRP) which is what the approach proposes. Allowing end users to be charged the DRP would reflect the reality that some end users are intimately connected to some generators[1].

This then introduces the question of what should be the price a storage facility pay for power access through the network for its imports. If an end user is to be charged the RRP, why should the storage benefit from a lower DRP? To allow storage to pay the DRP provides the storage with an unearned benefit in its arbitrage when it sells the power back to the grid, which will occur when the generators upstream of the congestion are not able to provide (ie there is no congestion) and the RRP is high. By allowing storage to pay only the DRP, this would provide the storage with a competitive advantage over other storage projects and so incentivise storage to locate upstream of congestion points rather than where they will provide the most value to the market.

Further, if the storage gets to pay the DRP, this will reduce the residue payable to the generators upstream of the congestion, resulting in a transfer of wealth from the generators to the storage and so reduce the value of DRP in assessing the cost of the congestion.

Allowing the storage an unearned benefit will not provide a benefit to consumers (which is the focus of the NEO); so the MEU considers that storage should be charged the RRP for their imports.

3. Value of information provision

The MEU considers that the information provided by the DRP approach has quite a specific purpose and should not be used more widely. In essence, the DRP provides the basis for assessing the value between maintaining the status quo and installing new transmission assets.

As the MEU notes above, generators should be able even now to fund transmission assets and earn firm access rights on the transmission network if they consider that this will be in their best interests. As noted above, the MEU considers there are even now instances where congestion is so great that it is patently obvious that the generators affected would benefit from funding transmission augmentations.

Where the MEU sees the main benefit of the DRP approach is where the benefit might be more marginal. The DRP would provide critical input into a cost benefit analysis by the generator(s) where the benefits might not be as clear cut as for other points of congestion.

If the data is available then it should be available to all, including AEMO, AER and TNSPs who are obligated to improve the benefits to consumers under the NEO.

[1] Such as where an end user has located specifically for a benefit such as taking thermal energy from the generator

4. Generators funding transmission infrastructure

As noted above, the MEU considers that generators should be able to fund transmission augmentations now. While the MEU can see the reasoning behind why the AEMC prefers the ability of generators to fund transmission assets to occur after the release of the first set of DRP analyses, the MEU considers that earlier implementation of generator funding is of greater priority.

With this in mind, the MEU considers that the AEMC needs to immediately develop the rules so that earlier implementation of generator funded transmission can occur now.

To prevent allowing immediate implementation will ensure that consumers will pay unnecessary premiums for their electricity due to the delay inherent in the AEMC phased approach.

5. IR-TUoS

The MEU provided significant input into the development of the IR-TUoS rule and while supportive of the IR-TUoS concept, considered that the final rule as implemented had many shortcomings. The MEU recommends that the AEMC team on this CoGaTI project should review the commentary provided by the MEU on IT-TUoS as the MEU considers that many of the points it made then are still relevant. In particular the MEU noted in its response to the second draft rule[2]:

> - "The current approach to setting transmission prices is well recognised as being based on a number of assumptions and arbitrary decisions. Whilst there is agreement that peak demand sets the sizing (and therefore cost) of transmission assets, in practice, demand at peak usage times is not widely used to set transmission prices. Further, over half of the TNSP revenue is derived from the user having the choice to pay on demand based pricing or consumption based pricing. Therefore, current prices are not strongly reflective of the costs each user imposes on the transmission networks. Despite these obvious detriments, the AEMC approach uses what are demonstrably non-cost reflective inputs to its modelling from which it draws its conclusions.
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> - To make the preferred approach possible, the AEMC requires all TNSPs to use a pricing method which not all TNSPs consider will give a cost reflective outcome. The AEMC requires all TNSPs to use the CRNP 365 day pricing approach even though some TNSPs consider a modified CRNP approach is better and others use demand based on 10 peak days or monthly demand. The result of this imposition will be that intra-regional pricing will be less cost reflective. The

[2] MEU "Comments on the Proposed Draft Decision" pp 4,5 available at https://www.aemc.gov.au/rule-changes/inter-regional-transmission-charging

AEMC then asserts that its preferred approach will be more cost reflective but fails to demonstrate that this is so!

- The AEMC uses modelling to assess which of the IRTC options it has developed will be more cost reflective and stable in price impact yet this modelling is quite specific to the IRTC and does not assess the wider impacts of the proposed models. Further, the modelling is based on the transmission pricing used by TNSPs which has been identified as not being all that cost reflective. It is therefore difficult to assume that the outcome using flawed data will result in a less flawed outcome.

- The AEMC's preferred approach results in inappropriate costs being “exported” to other regions. For example,

    - Other (importing) regions will contribute to the easement land tax imposed in Victoria to recover the government subsidy to aluminium producers (this might raise constitutional questions about the legality of one state to tax consumers in another state!)
    - As there is no requirement for transmission revenue to be optimised, other (importing) regions will contribute to the cost of assets in an exporting region which are oversized and have significant spare (unutilised) capacity.

- Using the results of the modelling, the MEU highlights that the AEMC approach delivers some quite bizarre outcomes, such as:

    - There is one region which is a net importer of power but is paid by the exporting region to take this power.
    - Even if there is no net inter-regional flow of power between two regions, one of the regions will have to make a payment to the other region.

With these points in mind, unless the AEMC can develop a better new Rule proposal that addresses all the concerns raised in this submission, the MEU cannot support the introduction of an inter-regional charge and recommends that the AEMC should not proceed further with this proposed new rule.

Whilst satisfying cost reflectivity appears reasonable on the surface, the MEU questions the benefits (either in the short or long-term) given the issues and complexities inherent in the new approach adopted by the AEMC. In fact, rather perversely, the AEMC will be introducing significant distortions (less cost reflectivity) to intra-regional transmission pricing. Overall, the MEU does not consider that the AEMC has developed a better rule than the current arrangements. The AEMC's rule change is not consistent with the NEO.

> In its response to the Discussion Paper, the MEU proposed an alternative model for the IRTC which did address a number of the anomalies and perverse outcomes seen when using the mLEC. The MEU suggests the AEMC should re-examine the MEU alternative proposal to identify if the approach provides a more efficient and equitable outcome for consumers."

With these observations in mind, the MEU points out that the current IR-TUoS rule is flawed[3] and the minor "tweaks" proposed for consideration (ie using average demand vs peak demand and including non-locational costs) will not make a flawed rule less flawed.

With regard to the issue as to whether peak demand or average demand should be applied, the MEU points out that the capacity of an interconnector is determined by many other factors than just the rated capacity of the interconnector[4] . The MEU notes that it is the capacity of the intra-regional network in both the importing and exporting regions and the dispatch pattern of generators at any particular time which all too often controls the capacity of an interconnector. This would tend to indicate that average capacity is a better basis for allocation than peak capacity.

The inclusion of the non-locational TUoS will exacerbate the existing flaws in the current IR-TUoS approach. The MEU points out that already in setting intra-regional transmission costs there are significant inaccuracies in the cost allocations and pricing approaches that limit cost reflectivity. The smearing of non-locational TUoS and Common Service charges already reduces cost reflectivity in intra-regional pricing. Further, the common service element of the transmission pricing is a significant element of the pricing structure and smearing this into the IR-TUoS would potentially over-compensate the exporting region. The MEU does not support including non-locational TUoS or Common Service charges into the IR-TUoS calculation.

It is recognised that intra-regional pricing is already non-cost reflective and the introduction of prudent discounts was a "least worst" approach to specific needs where for a specific end user the actual costs might lie closer to the avoided costs. A prudent discount is calculated on criteria specific to the end user who has sought the reduction in transmission charges. In the case of the IR-TUoS, the MEU is uncertain how a prudent discount could be calculated for an interconnector as the prudent discount criteria used for intra-regional charges relate to a specific end users and so cannot apply for general electricity flows between regions. The MEU considers that trying to develop criteria from the "particular" (ie the reasons for applying a prudent discount to a specific end user) to the "general" where there are no specific issues, will be a most challenging but probably fruitless exercise.

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[3] For example, using actual data, the AEMC carried out calculations for the IR-TUoS as part of its development of the IR-TUoS rule. In its response the MEU pointed out an absurd outcome where an importing region was paid IR-TUoS by the exporting region – ie that the exporting region transmission network paid the importing region the importing region network for receiving the electricity!

[4] Noting that the peak capacity might be available only occasionally but not on a consistent basis

6. TUoS Framework reform and timelines

The MEU does not consider that a general reform of the TUoS pricing framework is necessary to implement firm access rights as proposed in the current consultation paper. The MEU sees that FARs would be treated in the same way as either connection charges under the current framework or as customer contributions, ubiquitous in distribution networks. With this in mind, the MEU considers that any wider review of the TUoS charging approach does not need to be tied to the review of the firm access regime being developed for generators.

The issue of transmission pricing has been debated regularly over the two decades the NEM has been in operation and despite the many short comings about transmission pricing the MEU has identified in the past (eg during the transmission pricing review in 2006), the current arrangements have stood the test of time.

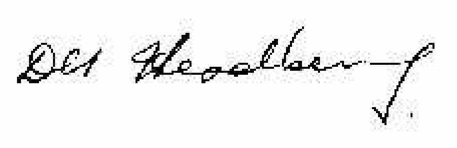
The MEU highlights that transmission pricing is intended to allocate the costs on a usage reflective basis but the ability to achieve this is extremely complex. The current arrangements are relatively well understood and the only criterion that the MEU would put on any future review, is that any change must deliver enhanced cost reflectivity.

As the MEU has noted in previous submissions, it has become very clear that the cost of network investments has been a major contributor to the very high cost of electricity supplies now being seen in the NEM and that the Regulatory Asset Base (RAB) of all networks has more than doubled in the past decade (in nominal and relative terms) with utilisation of these assets falling dramatically over the same period as demand has flat-lined and consumption fallen.

A major aspect of this observation is that consumers are paying considerable sums for assets that are either not being used or are only used to their capacity occasionally. The impact of the ISP is that the amount of transmission assets will increase further with time. A major issue for consumers is how the costs for any under- or un-used assets can be removed from the asset base. As the amounts of capital tied up in this way are enormous, addressing this unnecessary cost imposition of consumers should be the first stage of any review.

The MEU is happy to discuss the issues further with you if needed or if you feel that any expansion on the above comments is necessary. If so, please contact the undersigned at davidheadberry@bigpond.com or (03) 5962 3225

Yours faithfully



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