19 October 2020

Mr Ben Davis
Director
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Reference: ERP0073

Dear Mr Davis

AFMA Response to Interim Report on Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis

The Australian Financial Markets Association (AFMA) welcomes the opportunity to comment on the *Interim Report on Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis* released on 7 September 2020.

AFMA is the leading industry association promoting efficiency, integrity and professionalism in Australia's financial markets. AFMA represents the common interests of its members in dealing with issues relevant to the good reputation and efficiency and competitiveness of wholesale banking and financial markets in Australia. AFMA has more than 120 members reflecting the broad range of participants in financial markets, including Australian and international banks, leading brokers, securities companies, fund managers, energy companies and industry service providers.

Whilst acknowledging the overall objectives of the consultation paper, AFMA's financial markets focus means that our comments are limited to those areas relevant to the efficiency and competitiveness of electricity financial markets.

As raised in our previous submissions, AFMA members have real concerns about the proposed implementation of dynamic regional pricing and the significant implications it will have for forward contracting in electricity financial markets, which will hinder the efficiency and liquidity in these markets. AEMC's transmission access reform proposal (COGATI) will not directly manage the coordination challenge of building efficient transmission infrastructure in locations that best serve efficient generation decisions. While the reforms will alter generation locational decisions, this will not occur in the perfect way as suggested by NERA's modelling. We suggest that the current inefficiencies arising from disorderly bidding are also smaller than the modelling suggests. It seems that arguments in favour of COGATI reforms have not considered of the strength and value of existing locational investment signals and the liquidity risk for the contract market.

Issues such as difficulties in connecting to the grid and higher-than-expected curtailment are symptomatic of a lack of coordination of generation investment, with network upgrades often lagging generation build. Recently, generators have located in areas rich in renewables, which are often located in weak parts of the network. This trend is likely to continue, given the strong locational signals provided by state-based programs such as the renewable energy targets (RETs). Most recently, the Victorian Government has announced a second round of the VRET, which will drive further investment into renewables. In the absence of timely transmission augmentation appropriately coordinated with generation build, congestion issues, curtailment and delays in grid connections are likely to persist, including for VRET2 projects.

There are several risks of the proposed reforms that may impact negatively on many participants in the market and ultimately consumers. The reform creates significant risks and investment uncertainty resulting in disruption to existing long-term energy contracts and added costs for market participants due to the Locational Marginal Pricing (LMP) regime being proposed.

We are concerned the reform does not sufficiently address the key question posed by the CoAG Energy Council and has shifted from the original objective of coordinating generation and transition investment to improving access through congestion management.

While the proposal may result in more efficient short-term spot market signals, we think it is unlikely to address congestion. Further, while congestion does provide one type of locational signal, this is not the only factor to be considered. As noted, generator locational decisions are weighed against other key characteristics, such as availability of fuel source (high wind speeds/solar irradiation), land availability, ease of obtaining planning approvals and access to existing infrastructure.

It appears that analysis in the interim report does not comprehensively explore the implications to participants and consumers from both a physical spot market and financial contracts market perspective.

Simpler and more cost-effective market reforms could better address the emerging market risks. Transmission investment, including coordinated with generation investment, is now being considered outside the COGATI reforms, by other market, government and regulatory initiatives, such as REZs, actioning AEMO's recommended Integrated System Plan (ISP) projects and the transmission network service providers normal Annual Transmission Planning Report and Regulatory Investment Test for Transmission (RIT-T) process for projects to connect AEMO's ISP projects to the customer load centres. Locational information is also being further supported by the *Transparency of new projects* rule.

1. Response to September Consultation Paper

1.1. Locational Marginal Pricing Design

The Interim Report asks whether having non-scheduled participants face the Volume Weighted Average Price (VWAP) of LMPs of non-scheduled market participants will minimise impacts on the financial market and promote liquidity.

Over the interim period between final rule and effective date, and assuming the Regional Reference Price (RRP) is changed to VWAP, there are significant risks associated with renegotiation of existing contracts/Power Purchase Agreements (PPAs)/offer agreements by contract holders and counterparties. It is likely that a number of existing contracts will fall over because of renegotiation costs or the number/impact of contractual clauses means the agreement is no longer workable. This will likely reduce market liquidity. We request AEMC undertakes a specific market modelling exercise to assess this risk, and how it would play out if the Retailer Reliability Obligation (RRO) was also triggered (or if Settlement Residue Auction (SRA) prices dropped). The AEMC should also confirm how the SRA market would be wound back over this period, noting that existing SRA contracts could have legal effect over the same time period where contract renegotiation and initial FTRs (both transitional and auctioned) are assigned.

The consultation paper also asks whether static intra-regional Marginal Loss Factors (MLFs) with dynamic marginal losses will more accurately reflect losses on the network. Whilst the use of actual real time dynamic marginal losses will more accurately reflect network losses, the reduction in overall costs of losses will at best be marginal compared to the current annual average loss factor allocation.

Having loss factors that change every five minutes will create a lack of certainty over extended periods, making it far more complicated and difficult to predict when compared to the current approach. As such, we expect the introduction of dynamic marginal losses will have a negative impact on the level of contracting. Dynamic losses can increase volatility of losses, varying approximately +/- 20% from the average yearly losses. This will likely reduce the willingness of generators to hedge compared to the current system in place. Generators are settled on the basis of loss adjusted volume. At times of high system demand, and potentially higher prices, generator settlement would be subject to a higher value of losses under dynamic MLFs, resulting in lower settlement value at the node. In addition, dynamic losses would increase for some generators under network outage conditions, where higher priced dispatch outcomes would be more likely to occur. As actual losses under a dynamically calculated loss framework would be unknown until dispatch, in our view there would be high probability generators would adjust their contract position to avoid unfunded contract for difference payments, as Contract-For-Difference (CFD) payments in this case may not be supported by spot receipts.

1.2. Financial Transmission Rights Design

In its Interim Paper, the AEMC has since changed its view on the number of nodes available at the outset, outlining a preference to start access reform with a smaller number of pre-defined nodes. This may impact market liquidity by limiting the number of FTR "routes" available, and therefore the level of risk a contract could wear/assign. However, it could also increase competition for these routes, and therefore the value of contracts available.

Even if the use of a reduced number of predefined trading (zonal) hubs could reduce complexity and assist in the understanding of inter-zonal risks, basis risk between these zonal hubs remains for those that cannot secure FTRs. In addition, the proposed model retains price basis risk between the zonal hub price and the generators' LMP. This could be improved if generators in the Zone received the zonal price. As generators will only sell hedges based on FTRs held, uncontracted generators have an incentive to maximise profits via price/volume trade off in the physical market. Generators without FTRs will quickly work out the optimum contracting and dispatch level such that congestion does not bind, such that FTR payoffs are immaterial and speculators will face large losses from FTR purchase. Financial market hedging will suffer as generators will have incentives to not provide hedge cover to competing retailers.

The COGATI reform model proposed risks having a significant detrimental impact on the efficiency of contract markets, primarily due to increased risk and uncertainty and the added complexity brought by the introduction of LMP and FTRs, which may negatively impact investment signals and create a barrier to investment in new generation.

- The lack of FTR firmness means that nodal price risks will not be able to be addressed properly, meaning that a greater number of FTRs may be required. Where FTRs are not sufficiently firm, not available, or the duration that they are available does not match needs, generators may add risk premiums to cover uncertainty, and price in any volume and basis risk brought on from not being able to access FTRs (or alternatively just sell at point of production, leaving buyers to manage the risk of a constrained transmission grid).

- As FTRs will remain limited to a conservative level set under existing network capacity, a large number of participants are likely to be exposed, which will have a broad impact on the financial market. Risk departments may limit the extent to which counterparties trade across multiple nodes without FTRs. Financial market traders that normally add significant liquidity may be less likely to participate in a larger number of smaller markets. In addition, credit risk may also increase because contracts issued under COGATI may be produced by less credit-worthy counterparts or without clear contractual directions outlining how risks are managed/allocated. This is all combined with the additional uncertainty around how the market will actually evolve, and which products will deal with financial risks. There is also a risk that current product development underway to better facilitate hedging across different times of day to accommodate non-firm renewables may be stifled.

- The introduction of more complex arrangements under the September 2020 model (VWAPs, dynamic losses and staggered FTR auctions) may increase the likelihood of prices for financial instruments not reflecting underlying value because of imperfect information. Many contracts across an increased number of nodes with much analytical investment would be required, favouring more active or resourced market participants, with riskless profits being possible (which goes against idea of perfect market efficiency). While FTR speculation by financial intermediaries is already a large profitable feature of NZ market, the AEMC has typically ignored the role of intermediaries, focusing on the financial market as a point to point exercise (with retailer A buying direct from generator B).

1.3. Quantitative Impact Assessment – NERA Cost Benefit Analysis

The NERA modelling seems overly simplistic and is not representative of the NEM's topology. Transparency of the modelling inputs is required to determine if there is an explanation behind the highly surprising results. On the information provided, NERA has not demonstrated that they understand the physical market or how the forward contract market operates (and as a result, its modelling looks to be founded on incorrect assumptions).

The NERA modelling suffers from severe limitations which bring into question the practicality of the outcomes and benefits put forward, which appear to be substantially overestimated. Some of the key limitations include that the modelling:

- does not incorporate other significant market design changes being considered, nor does it appropriately consider the impact of non-market incentives such as renewable energy targets;

- was based on the draft ISP and does not include Renewable Energy Zones (REZs), even though they would alleviate congestion concerns and would likely reduce the benefits of reform;
- does not take into account implementation costs, including costs of system changes and IT implementation;
- severely underestimates the impact on financial markets, in terms of the costs of recontracting and reopening of wholesale contracts and PPAs;
- outlines outcomes (such as low prices in the short-term) and choices (such as modelling storage as a peaking generator) that are not realistic and may not be appropriate for real world use; and
- does not explore the transitional impact of reforms in terms of investor risk or associated costs for customers being higher due to the inherent complexities in managing congestion risk.

As a result, we do not consider the model to be a good indicator of how fit for purpose the current access regime is, nor a good basis for judging how congestion risks might change over time.

The introduction of transmission access reform would increase risk for generators as they would face an additional price risk, in addition to volume risk. While the proposal includes a hedging mechanism in the form of financial transmission rights (FTRs), this mechanism is only needed to deal with the introduction of basis risk from the reform in the first place and will not provide a perfect hedge.

The modelling fails to account for the costs of FTR purchases and the impact of this on contract prices. We disagree with NERA's assumptions around contract market liquidity and believe there is a significant concern about impacts of the reform to market liquidity of scheduled generation receiving the LMP.

Overall, the modelling does not have any bearing on the nature of congestion risk and how this should be best allocated, particularly the roles of transmission network providers and AEMO in managing the system. The analysis presumes that congestion risk should be entirely borne by generators who are able to mitigate this through locational decisions, which is overly simplistic.

The reforms may result in generators selling energy at the generator's gate (local connection node), rather than the regional reference node, transferring risks to retailers or end use customers who may not be able to properly manage the risk with securing FTRs. The reforms will also impact Exchange of Futures for Physicals (EFP) contract liquidity as a means for managing credit risk.

It appears that the challenges around transition have been significantly understated, particularly regarding the legal costs of recontracting and likely reopening of wholesale contracts and PPAs. The four-year implementation/transition period proposed will not be sufficient for PPAs which will need to be renegotiated at considerable expense, and with real lasting impacts on risks for renewables investment.

NERA's modelling does not explore the transitional impact of reforms in terms of investor risk and associated costs for consumers due to inherent complexities of managing congestion risk. Better price signals cannot influence the decisions of existing generation plant in terms of locational decisions to manage the new congestion and price risk being introduced.

Though NERA's modelling of how the shift to LMPs would affect physical dispatch and investment patterns appears thorough, the treatment of financial market impacts is highly theoretical. The actual delivery of market benefits will depend on FTR trading and contract markets generally, which will not operate as perfectly as NERA assumes.

There has also been an overestimation of a wealth transfer due to the lack of proper consideration to the implementation of REZs, including the transmission investment in shared network capacity that will be undertaken to support REZs as well as the up to date information on ISP projects. The CBA work undertaken by NERA only included specific ISP projects – Group 1 and Group 2 projects from the Draft 2020 ISP – and did not include any REZ network extensions indicated in the Final 2020 ISP report or network augmentation projects listed in the network service providers annual transmission planning reports.

There also appears to be a lack of transparency as to whether the jurisdictional transmission reliability standards for reliable supply to consumers has been met in the reform case, given the use of AEMO's Draft ISP project plan only, without inclusion of the necessary supplementary transmission investment required to support these network augmentations.

1.4. Implementation and Transitional FTR Arrangements

A number of issues need to be considered prior to the implementation of any access reform. Transitional impacts to the contract market have not been properly contemplated, in particular, the significant risks associated with renegotiation of existing contracts/PPAs/offer agreements by contract holders and counterparties. A four-year implementation period is not sufficient to allow pre-existing contracts to expire prior to commencement. Existing contracts would fall over because of renegotiation costs or the number/impact of contractual clauses means the agreement is no longer workable.

The proposed reform model introduces basis risk associated with congestion, which can be covered where FTRs are purchased and will always pay the full amount of price differences in the presence of congestion. This 'revenue sufficiency' condition and the associated 'firming' of FTRs depends on perfect foresight of the state of the transmission network at the time of FTR auctions, which are proposed to occur progressively from 10 years in advance.

Though the AEMC has attempted to address some liquidity concerns in the September Interim Report, there are key areas where liquidity needs to be tested further.

- AEMC assumes that generators will buy transmission rights, which may not in fact occur. If instead, generators decide to only sell financial contracts at the point on the grid that they are connected, rather than at a central point (i.e. the node in each state), there will be a breakdown of liquidity due to a reduction in the number of homogenous products traded at respective state nodes.

- It seems clear that some proportion of contracting volume will be pushed to local nodes and settled at LMPS, fracturing traded volumes across numerous nodes. The introduction of basis risk between the LMP and the node will have implications on liquidity as generators seek to transact at the LMP.

- Any reduction in contract market liquidity will have flow-on impacts on the RRO or any future Resource Adequacy Mechanism, the ability of retailers to access contracts, and the ability of generators to comply with the Market Liquidity Obligation. These impacts have not been addressed in the AEMC's work to date.

- Trading activity of generators will likely be limited by the availability of FTRs, meaning the flow of contracts will centre around FTR auctions, making contracts scarce at times which will impact trading flow. The risk of a situation where there are insufficient transmission rights available at a time when an LMP is low, whilst the RRP used to settle contracts is high, adds an additional layer of risk that buyers and sellers will need to factor into their contracting risk frameworks and contracting decisions.

- To reduce risk, generators may make fewer contracts available in each region, resulting in a detrimental outcome for contract market liquidity and customers who rely on contracts for retail pricing certainty. The retail customer ultimately will be unable to obtain contracts at times or pay a premium for the risk associated with the floating FTR exposure.

- Having the number of FTRs available at a lower volume than the current physical network capability may not meet the minimum required to maintain the existing level of contract liquidity in order to increase "firmness". This will also lower the volume of firm contracts able to be traded. Participants may be incentivised to delay the purchase of FTRs until closer to real time, when their likely value is better known, which may also cause an associated withholding of other contract purchases.

- The complexity brought by COGATI will also add to need for credit support. If financial market traders do not participate in the large number of smaller markets, then this will cause liquidity issues.

The significant impacts on contract market liquidity and market interactions should be subject to independent modelling under a further market assessment by the AEMC. While AEMC have now allowed both physical and non-physical participants access to FTR auctions, which may increase competition, and hopefully the number of contractors in market, this should be analysed further.

2. Alternatives to Transmission Access Reform Proposed

While existing locational signals such as marginal loss factors and constraints may be sufficient to deliver lowest costs for consumers, alternatives approaches to addressing the issues that AEMC's transmission access reform seeks to address include:

- Integrated System Plan - the ISP is effective and in time will be able to solve transmission related issues without the significant market disruption of COGATI. The ISP provides regulated central planning of new transmission investments/grid augmentations, leaving the market to determine (in line with other market signals) the best locations for generation investment. A developer still wears the risk and associated costs of a bad investment decision, so future congestion will naturally dissolve itself. The SRA auctions mechanism should also continue to operate as it can be reviewed or re-purposed for transmission/interconnector use and charging frameworks.

- Renewable Energy Zones - unlocking REZs and establishing mechanisms for a sharing of costs between connecting parties, (noting that the cost of building transmission to new geographic locations needs to be carefully considered to ensure consumers don't ultimately wear excessive costs for new transmission.) A REZ framework integrated with other existing market reforms (i.e. NEM 2025 Review market design initiatives and other AEMC rule changes) could deliver a platform for 'as close as possible' coordinated new investments.

- Increased transparency - improved information provision between Network Service Providers (NSPs) and participants (including connecting parties) such as additional data on congestion and losses (and which may need to build on the recent rule changes which provided for greater transparency with potential and planned generation projects). More transparency and release of information on network hosting capabilities and timing/location/size etc. of intended connecting generation should also improve locational signals.

- Other initiatives under the ESB Post-2025 Market Design project, which is addressing the emerging system security challenges, including system strength issues, after which the necessity for access reform should be reconsidered.

- Changing dispatch during instances of tie-breaking, which could include preference to generators based on when they connected, or other dispatch/ bidding rules that target more efficient plant. This solution would need to be refined but is still likely to be a far lower cost option that directly targets the incentive for disorderly bidding, the removal of which constitutes the bulk of COGATI's expected benefits.

More targeted transmission planning around known and likely areas of congestion are likely to occur without COGATI reforms. Where the build-out of congestion to meet connecting generation is in line with optimal system planning (e.g. as per locations and timing in the ISP, and in detailed REZ plans) this can be recovered under regulated transmission revenues. Where it is not, funding models are under consideration for generators to fund investment and determine associated access rights themselves with the relevant Transmission Network Service Provider (TNSP).

***

AFMA understands that the AEMC's Transmission Access Reform proposal is one of several proposed market design initiatives under consideration as part of the ESB post-2025 market design project. This project is a massive undertaking with a vast range of approaches and combinations of initiatives possible to deal with the challenges involved with reforming the national electricity market. We ask that the role of the contract markets is properly considered, so that market participants are able to manage risks and costs associated with the changes while ensuring the security and reliability of the electricity system now and into the future.

Please contact Natalie Thompson either by phone on 02 9776 7979 or by email nthompson@afma.com.au if further clarification or elaboration is desired.

Yours sincerely

David Love
General Counsel & International Adviser