ERM Power Limited
Level 3, 90 Collins Street
Melbourne VIC 3000
ABN 28 122 259 223

+61 3 9214 9333
ermpower.com.au

Monday, 19 October 2020

Ms Victoria Mollard
Director
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Ms Mollard

RE: Transmission access reform: Updated technical specifications and cost-benefit analysis, 7 September 2020

ERM Power Ltd (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission (AEMC)'s Transmission access reform updated technical design paper dated the 7th September, which provides an overview of the AEMC's latest thinking around its proposed transmission model and an overview of the Cost Benefit analysis undertaken by AEMC's appointed consultant, NERA .

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fueled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

http://www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

KEY POINTS

- CoGaTI reforms have moved away from the original remit of addressing coordination between generation and transmission investment and are now disproportionate to the scale of reform that is required.
- NERA modelling has drastically overestimated benefits and understated risks of the reform. The proposed reform will create a riskier environment for investment in generation, hindering the transition of the market.
- Other reforms currently underway are better placed to address the coordination between generation and transmission investment.

General Comments

Developing appropriate policies for the coordination of investment in generation and transmission infrastructure (CoGaTI) in a market that is undergoing rapid and significant transformation and in a way that does not damage the

[1] Based on ERM Power analysis of latest published information.

efficient operation of the physical and contract markets or create barriers, is a challenge facing policy makers in the National Electricity Market (NEM) as it is in many other energy markets around the world. Driving this immediate and accelerating transformation is a changing mix of supply, with the entrance of new Variable Renewable Energy (VRE) and with it, the changing economics of generation and the consequential closure of large thermal plant, the expansion of distributed energy resources such as batteries, and more responsive, price sensitive demand with demand response and smart appliances. This transformation of the grid requires careful planning and policy response to ensure the market continues to operate efficiently and that investment in capacity meets the requirements for reliability and system security, affordability, and emission reduction efforts.

We see the critical need for careful and considered policy around coordinating transmission and generation investment to ensure a well-designed system provides a favorable environment for investment to make it resilience to the pace of change. We are deeply concerned that the proposed access arrangements being promoted by the AEMC falls well short of these objectives and has in fact moved off track from the original remit of addressing coordination between generation and transmission investment. Instead, the proposed reforms are massive, complex, and disproportionate to the scale of reform that is required. ERM Power is deeply concerned that the model, if implemented, will disrupt and damage the investment environment that is required to support the industry's transition and will potentially lead to the premature closure of existing generation leaving the NEM vulnerable to reliability issues.

Despite overwhelming concerns raised from all parts of the industry that the proposal will not address coordination of generation and transmission investment issues and will instead cause unmanageable risks, investment uncertainty, major disruption to existing wholesale contract markets and added costs for market participants and consumers, the AEMC remains emphatic in its pursuit of a Local Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) model for the NEM. The AEMC now anticipates providing a rule change package by the end of the year to Ministers and seeks the implementation of CoGaTI timed with the ESB's NEM 2025 project.

Adopting these reforms are likely to create unintended consequences, unmanageable risk and investment uncertainty and will create an environment that hinders the market's transition, the aspirations for Renewable Energy Zones (REZ) development and the implementation of the Integrated System Plan (ISP), and we urge the AEMC and policy makers look to other reforms that are delivering the desired outcomes in generation and transmission investment.

So, if the AEMC's model for Access is inappropriate and disproportionate, what is needed?

We believe coordination of generation and transmission investment reform should consider the integrity of existing planning frameworks and opportunities to improve them and the key question of how the expansion of the transmission network should be funded, rather than gambling on a major redesign of wholesale pricing which introduces barriers to participation.

A more appropriate path to align generation investment and transmission decisions based on infrastructure and capacity needs will be achieved with proper planning, further improvements to information transparency and execution of a process to facilitate development of Renewable Energy Zones (REZ's) and improvements to ensure effective stakeholder consultation in the development of the Australian Energy Market Operator (AEMO)'s Integrated system plan (ISP), supported by a functional regulated investment test for transmission (RIT-T) process that considers consumer benefits as well as market benefits.

There can be no doubt the NEM will need to develop additional transmission resources to facilitate the transition of the power system. The major concern of consumers is that the current frameworks impose all costs and stranded asset risks of this transmission investment on consumers. In our view, the proposed reforms fail to adequately address consumer concerns in both these areas. Submissions from consumer representatives to date have been clear in their expectation that the CoGaTI review should have considered a framework for a beneficiary pays approach for new transmission investment.

The **RIT-T process**, whilst detailed in some areas, has been shown to be wanting in practice. Network service providers are able to understate the costs of projects during the RIT-T approval process and then increase costs at a later date when seeking funding approval, or not disclose actual costs upfront and include them in their regulated asset base (RAB) by deferring other capital expenditure projects and then reincluding these in the next regulatory approval period. In addition, from a good governance perspective, allowing the project proponent to be responsible for the calculation of all potential benefits from a transmission investment is of concern. We believe independent modelling of calculated benefits is required with the independent modeler selected by the Australian Energy Regulator (AER).

Whilst some reforms have been introduced in the area of new **project transparency**, there are further reforms needed in this area, both from a mandatory information provision perspective and AEMO publication of additional details such as connection point location.

The **REZ framework** is expected to provide an orderly path for renewables development, promoting efficient and effective connection of generation to transmission and with consideration of system security issues. The transmission development required to connect a REZ will need to consider the design of the broader transmission network at an early stage. Much of this will be served through consultation with a broad range of stakeholders at the concept design stage to ensure that proper REZ planning considers that there is adequate and efficient use of network infrastructure.

The 2022 **ISP** will be the first prepared under the new best forecasting practice and cost benefit analysis guidelines. These new guidelines set out frameworks which should, if properly implemented by AEMO, result in effective stakeholder engagement during the development of future ISP's. We intend to monitor implementation of the guidelines by AEMO as we take part in the stakeholder engagement process in the development of the 2022 ISP.

Overview of this paper

This paper looks to NERA's analysis and raises concerns that NERA's model has produced a calculation of idealistic but highly improbable outcomes for the future NEM. We challenge several of NERA's assumptions and consider that NERA has taken a narrow view of the wholesale contract market and its impact to customer costs. We have concerns around liquidity that are contrary to NERA's findings. We do not support the regime proposed and believe it will cause harm to the investment environment and the future functioning of the NEM.

We thank the AEMC for proving us opportunity to gain insight to their thinking and detail around the AEMC Access model. We do not support the proposed Access reform as it fails in its intent and will result in increased costs to consumers who are already struggling with high energy costs. We welcome continued discussions with the AEMC and policy decision makers on how desired outcomes for the efficient coordination of generation and transmission investment could be more appropriately delivered.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

[signed]

Libby Hawker

Senior Manager Regulatory Affairs

03 9214 9324 - lhawker@ermpower.com.au

NERA MODELLING

Social Benefits

Disorderly bidding is not a problem for the NEM and should not be used as an issue to drive this policy reform.

Unlike the theoretical outcomes produced by NERA's model where a simplistic digital switch was used to impose disorderly bidding by all generators in a NEM regional zone, it is our view that disorderly bidding is not an endemic issue for the NEM and therefore NERA's modelled efficiency gains will be significantly over-estimated to what is occurring in the NEM. NERA's modelling considers the theoretical benefits that may result from the Reform where generators, priced at their local node would only be incentivised to submit cost reflective bids. It is unclear in NERA analysis whether any weight has been given to other factors and conditions that may influence bidding strategies such as the commencement of Five-Minute settlement, fuel availability, contract levels and physical plant limitations. Further, we consider the growth in VRE such as grid connected solar PV and thermal generator retirement will minimise any dispatch efficiency gains, given such generators all have effectively a zero short run marginal cost (SRMC).

The AEMC asserts the elimination of disorderly bidding will produce dispatch efficiencies by removing the potential for uneconomic dispatch of generators, leading to lower overall resource costs, but not necessarily better market price outcomes. Congestion related disorderly bidding such as 'race to the floor' type bidding behaviour is characterised by a generator, facing the prospect of being constrained off at times of high spot prices, rebidding capacity to very low prices and reducing the rate it can be ramped down in an effort to limit the extent to which their dispatch levels will be decreased. NEMDE may then constrain other lower cost generators, or those further away from the constraint to a greater extent. Constrained on generators at times when spot prices are less than the costs of production may also be incentivised to seek to recover their costs by bidding unavailable and hoping for AEMO to issue a Direction to dispatch.[2] Other impacts may include counter-price flows on interconnectors where disorderly bidding by a remote generator in a congested region results in electricity being exported from a high price region into a lower priced region to manage congestion.[3]

NERA's modelling sought to measure the difference between the total system costs under the status quo (No Reform) and the regime implemented (Reform) for 2025, extrapolating an estimate of a 'race to the floor bidding' scenario, and based on an estimated volume of coal generation on the system. The analysis suggested that total system costs could decrease by around $180 million per year (upper bound) and $140 million per year (lower bound) due to the elimination of race to the floor behaviour[4]. These savings are calculated in the absence of any evidence or indeed investigation that the prevalence of 'race to the floor behaviour' is afflicting the NEM resulting in distorted price outcomes for customers.

We note that AEMO raised concerns around whether "disorderly bidding issue is material"[5] in their submission to the AEMC's proposed access reform. The question of whether a defined and material disorderly bidding problem is

2 Generators in the NEM unlike other electricity markets don't receive compensation for being constrained on where spot prices are lower than their cost of production
3 Counter-price flows are a feature of the selected constraint equation formulation. Other formulations which prevent counter-price flows could be used.
4 NERA Cost Benefit Analysis (CBA) of Access Reform: Modelling Report, 7 September 2020 page iv
5 AEMO response to Coordination of Generation and Transmission Investment – Proposed Access Model Consultation Paper 2019, 8th November 2019, page 4.

plaguing the NEM remains unanswered and was not considered by NERA's modelling, but rather NERA just assumed it is a given - a widespread problem that exists and set the modelling methodology to prove this. There has been no evidence provided of a worrying prevalence of disorderly bidding in the NEM or that any such issue is indeed producing meaningful price outcomes that will impact consumers.

Previous reviews on disorderly bidding do not support NERA's findings

Various reviews have not identified inefficiencies to the extent provided by NERA. A definitive report into the direct costs of disorderly bidding in the NEM was undertaken by Frontier Economics for the AEMC's Congestion Management Review which considered outcomes in financial year 2007/08. The report calculated the change in production costs associated with disorderly bidding was $8.01M, this represented 0.47 percent on total NEM costs in that year.

We note that as part of the AEMC's Transmission Frameworks Review, the Commission indicated that;

"*A key focus of the review is to assess the extent to which the existing market arrangements are able to manage congestion both currently and in the future*.[6]" and "*The Commission therefore considers that a critical part of the review will be to assess, and form a view, on this issue. To form a basis for this work, we have developed an economic assessment framework for establishing the materiality of congestion, which is set out in Appendix A*."[7]

However, the Commission at that time did not seek to replicate the work undertaken by Frontier Economics in 2008.

As part of the initial CoGaTI review in 2018, Ernst and Young was commissioned to undertake a similar review to that undertaken by Frontier Economics in 2008. This review was based on market outcomes during financial year 2017/18. The stage 2 Discussion Paper noted that:

"I*n summary, it can be seen that there is limited congestion at the moment within the NEM. To the extent that congestion occurs, it is largely limited to between regions (i.e. inter-regional congestion), or is congestion occurring at the ends of the regions which is translating to congestion being observed on interconnectors. We understand that studies on upgrading interconnectors is currently underway by nearly all TNSPs in the NEM."*[8]

"This analysis is also consistent with AEMO's analysis of congestion for the ISP. Specifically, the below figure (replicated from the ISP) highlights areas of network congestion during 2016-17 – it can be seen that the results are similar to the EY work. This figure shows that the bulk of network congestion in 2016-17 resulted from interconnector transfer limits, signalling there may be a need to analyse if there is value from upgrading interconnection. AEMO also note that these patterns of congestion could change in the future, depending on when and where generation resources connect. We understand that AEMO is seeking to undertake modelling showing future congestion patterns in the final ISP."[9]

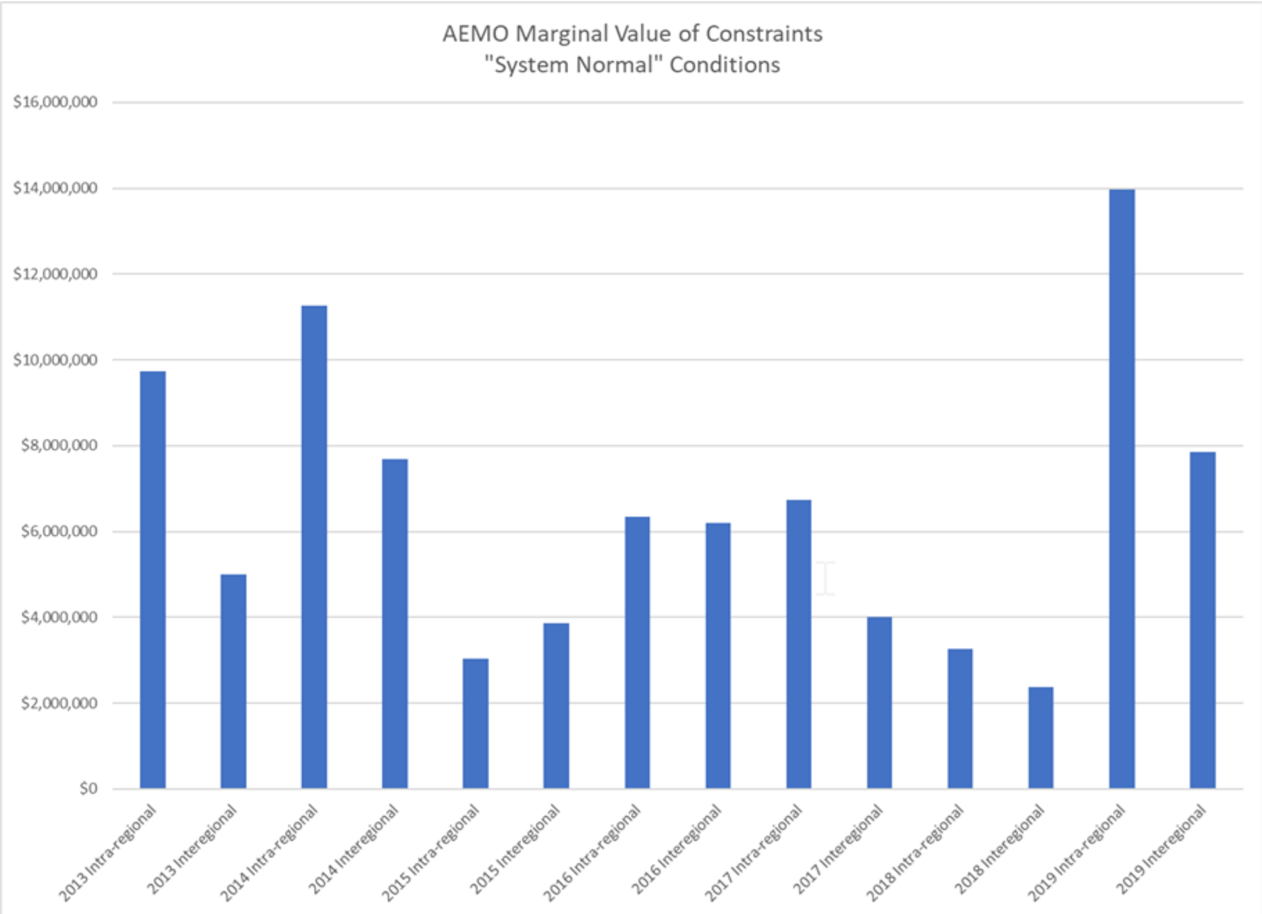
With specific regards to the total cost of congestion as set out in the Ernst and Young report:

"The results show that the cost of congestion in 2016/17 was just under $17 million (or 0.36 per cent of total actual AEMO dispatch). This is relatively small in the context of the NEM"[10]*.*

In addition, AEMO produces an annual Marginal Costs of Congestion report which details the marginal costs of congestion on an individual binding constraint basis. The data provided allows segregation by intra- and inter-

6 AEMC 2011, Transmission Frameworks Review, Directions Paper, 14 April 2011, Sydney, page 52
7 Ibid, page 54
8 CoGaTI Review Stage 2 Discussion Paper April 2018 Page 40
9 Ibid Pages 40 and 41
10 Ibid Page 42

regional constraints as well as system normal, outage and special security constraints. We consider that the key congestion area for monitoring of the impact of network congestion and potential for disorderly bidding is system normal constraints, given the wide transient variation in network outages. Given planned ISP projects will build out most, if not all inter-regional congestion and a number of key intra-regional constraints in the interconnector flow paths which impact interconnector congestion, we consider those constraints associated with intra-regional congestion to be the most representative for flagging potential issues which could lead to disorderly bidding. However, we note that this potential for disorderly bidding will be overstated when only one generator is affected by the congestion. The most recent annual report shows no significant deterioration trend in intra-regional network congestion under system normal conditions between calendar years 2013 and 2019.



Given this contrary evidence shows that the costs of congestion and therefore the potential for disorderly bidding in the NEM is not material, or trending upwards, we do not accept the NERA analysis, and consider the findings that by 2025 the costs of congestion in the NEM will be a 10 times multiple of that calculated in 2018 as flawed. This is occurring at a time when price outcomes in the NEM are reducing and the ISP and NSP's annual transmission planning reports (APR's) are indicating significant investment in reinforcing the transmission network, counteracting NERA's findings even further.

We also note that rule changes such as Bidding in Good Faith Rule (made in 2016) and Five-Minute settlement (commencing Aug 2021) have already been made to curb any bidding behaviour that deliberately distorts efficient price outcomes. Further, changes in the framework for the provision of power system services and the development of REZ's and their supporting transmission networks will reduce the potential for disorderly bidding.

We see that the potential impact of disorderly bidding will be even more trivialised as further VRE with the same SRMC enters the market and thermal generators optimise operations or exit.

The LMP/FTR model will create a riskier environment for investment in generation.

ERM Power are sceptical of the overwhelming benefits outlined by the NERA report relating to improved efficiency of investment in new generation, storage and transmission due to LMP signals championing the ideal locations for investment. The modelling points to large wealth transfers and economic efficiencies that are to be realised from exposing participants to their LMP, reflecting the locational value of the energy they produce. It is argued local generation price signalling will result in better investment decision making around locations and provide opportunities for capital and fuel savings from using the network more efficiently, ultimately driving less investment. NERA's assertions of capital cost savings in the NEM warrant careful consideration, particularly as NERA was unable to find such evidence elsewhere in markets that have adopted LMP price signalling[11] and was only able to draw limited conclusions from ERCOT in the US.

In considering the NERA modelling with respect to the level of optimal generation capacity required to meet forecast NEM conditions in the future, from both a power system security and consumer reliability issue, we note a considerable difference between the views of the system operator AEMO, as set out in the 2020 ISP and NERA as set out in their report to the AEMC. AEMO considers that by 2040 a combined total of approximately 100 gigawatts (GW) of installed capacity is required to sustain operation of the NEM, while NERA in its Reform case suggests only 90 GW of installed capacity is required. NERA then suggests in the Non-reform case, 110 GW of installed capacity will be built with this 20 GW difference comprised primarily of grid connected solar. The NERA report contains no details about the significant difference in the level of optimal generation capacity between NERA's modelling and that set out in the ISP. This raises questions with regards to the veracity of NERA's modelling overall.

NERA's No Reform modelling results seek to suggest an overbuild of 20GW capacity by 2040, (or 10 GW compared to the ISP), predicated on assumptions that inefficient locational decision making continues with congestion rising and compounding in the status quo (No reform case) and that prices to consumers will be higher due to generators earning congestion rents. It is unclear to ERM Power how a rational investor would seek to locate to extract congestion rents as implied by NERA given the known impact of such a decision on loss factors and volume risk. We believe a rational investor will seek to do the opposite to NERA's suggested outcome.

The level of future congestion in the NEM will be proportionate to two key factors, the development of the transmission network and the actual location of new supply side resources. We are troubled that NERA's modelling has drastically skewed benefits towards the Reform case and find issues with the following:

- The offline calculation of incremental transmission investment looks only to be a reinforcement of transmission / upgrades as set out in the Draft 2020 ISP and lacks consideration of other currently foreshadowed transmission investment required to both connect and support REZ development and additional augmentations as set out in the Final 2020 ISP. It also overlooks transmission investment set out by NSP's in their APR's, which will be developed to deliver generation to required parts of the network to meet consumer demand.
- The modelling restricts the construction of new wind farms to REZ's and allows new solar farms to locate at any point including within a REZ. This is a reasonable assumption; however, the modelling then strands this generation investment by not including the new transmission to connect and support it. The modelling

[11] NERA Costs and Benefits of Access Reform Prepared for the AEMC, 9 March 2020, page 27.

also dictates that firming generation cannot connect to a REZ but must instead connect at a node outside the metropolitan area which already has existing generation. This prevents firming generation from sharing network assets with VRE generation where it would be a rational outcome for them to do so.

- The modelling gives full weight to LMPs providing the primary economic incentive for locational decisions, failing to consider other integral drivers of locational decisions such as input energy resource availability, access to land and planning approvals which may provide greater economic efficiency in decision making. The modelling does not consider the potent influence of optimal resources' proximity when siting VRE (or increased capital costs for lack of siting in economically optimal areas).
- The modelling largely ignores the impact and costs of securing of FTRs which may distort locational signals or dampen them. The regime proposed by the AEMC does not actually eliminate congestion rents arising from pricing differentials but reallocates them according to financial hedging from the FTR holding, distorting locational signals over the FTR horizon.
- It assumes that all decisions will be based on perfect LMP signals in the Reform case and that unrealistically, generation will continue to make poorly informed locational decisions unabated in congested areas in the No reform case. This has significantly skewed the outcomes of the modelling with a higher cost of dispatch in the No Reform case.
- Until 2035/36, no benefits to consumers in the form of reduced "congested rents" accrue, theoretical benefits as calculated only accrue after this date.[12] This outcome where theoretical benefits only accrue well into the future should question the probability of actual benefits occurring.
- The modelling ignores the impacts on the contract market and the changes in dispatch outcomes which will occur for changes in generator contracting strategy.
- The requirement for FTRs to hedge the additional basis risk stemming from the reforms to meet new investment financial closure will not provide downward pressure on the cost of capital but rather the opposite, increasing projects' WACC due to the need to procure FTRs and which will create uncertainty, given investment returns will be dependent on FTR acquisition which will also be variable to FTR firmness.
- The proposed regime whilst allowing connecting generators to fund network augmentation does not directly allocate the additional FTR's created by the augmentation to these generators and the rules do not prevent other non-contributing generators connecting to these funded connection assets. The proposed regime creates no incentive for funding of network augmentation by generators.

We believe the proposed LMP/FTR regime will create uncertainties and negatively impact the investment pipeline. With exposure to new FTR costs, entry may become prohibitive and barriers may place jurisdictional targets for VRE penetration and emission reduction at risk. New investors will only tend to enter the market where they expect that the price they receive is above their long run marginal cost, enabling recovery of their variable operating costs and fixed and investment costs. The LMP/FTR regime saddles investors with the unknown costs of FTRs and an inability to source sufficient volumes of FTR's prior to making an investment decision due to the progressive auction process, and places new basis risks that may not be sufficiently hedged with reasonable certainty through an FTR.

It is our view that the policy objectives of better siting of generation and the efficient provision of new capacity is best addressed by increasing transparency of information, such as through the long-awaited Transparency of New Projects rule implementation and AEMO publishing other useful information such as connection point location.

ERM Power does not believe that the LMP/ FTR regime is the right policy to incentivise investment in the required location, given it is likely to be an imperfect price signalling regime. We believe sufficient locational signals are

[12] Figure 4.2 NERA Cost Benefit Analysis of Access Reform: Modelling Report Page 44

provided now through the application of Marginal Loss Factors, existing congestion information and inter-regional price variation. We consider that there are far superior policies that will directly deliver improvements to the coordination of investment decisions for transmission and generation in the future grid rather than the nodal pricing model being pursued by the AEMC.

Introducing Dynamic loss factors will lead to volatility in losses, adding further to investment uncertainty and may be detrimental to the contract market, at a cost to consumers.

Currently a precalculated annual average transmission loss factor is applied to generators and loads in the NEM. NERA estimates that the introduction of dynamic loss factors, where loss factors change every 5 minutes for both generation and load will produce a social efficiency benefit of $102 million, (in the sample year July 2025 to June 2026) , or $661 in NPV terms to 2040 though potential improvements in dispatch efficiency. Although unable to decouple and quantify the individual benefits, NERA points to a volume effect and price effect but expects that any volume effect benefit would be partially mitigated by AEMO though its adjustments to its five-minute ahead demand forecasting methodology. NERA also acknowledges that:

"*Our approach to quantifying the benefits of introducing dynamic losses is likely to be an overstatement, at least insofar as it is an estimate of the increased efficiency of short-run dispatch*."[13]

We agree with NERA's acknowledgement and believe based on the methodology NERA's overstatement of any potential benefits may be significant.

Unlike NERA's assertion that the introduction of dynamic loss factors will have a positive impact on investment, we see that this is less straightforward and greater investment uncertainty may appear. We are concerned that NERA's analysis has failed to consider that:

- Current annual MLFs provide certainty around contract volumes for risk management purposes and are easily accommodated as pass through on customers contracts and bills. This provides certainty to retailers and customers.
- NERA's modelling assumes a static and stable demand and generation supply outcome through each dispatch interval. The dispatch efficiency volume risk as claimed by NERA is insignificant compared to efficiency losses associated with normal demand and VRE generation output fluctuations, which is efficiently managed by the frequency control ancillary services markets. As acknowledged by NERA, any ongoing improvements by AEMO in operational forecasting in reducing the volume impact reduces any potential benefits determined by the modelling.
- Any dispatch efficiency gains (highlighted by NERA) would be negligible for increasing volumes of VRE generation with zero SRMC; and
- dynamic loss factors are inherently volatile, typically up to +/-15-20% (as currently calculated by AEMO) from the average yearly calculated static losses at the local node level. Dynamic loss factor volatility increases at times of higher variance from system demand and is generally higher during periods of higher demand and prices when higher network loading conditions are experienced.

As a result of this volatility in dynamic losses, we expect that generators will be less willing to hedge to the same levels currently, causing harm to contract market liquidity. This would coincide with an expectation that retailers will need to hedge additional volumes to cover the loss increase on loads. At times of medium to low system demand

[13] NERA Cost Benefit Analysis of Access Reform: Modelling Report Page 61

and lower prices, retailers may find themselves over hedged, the costs of which will then flow through as increased retail risk costs to consumers.

We also note NERA's qualification that:

"*Our method does not address the impact of introducing dynamic loss factors for investment in the system*."[14],

but in NERA's view that the dynamic losses with have a positive impact on investment due to the introduction of a more granular price signal, however NERA adds further qualification to its view in that:

"*static loss factors are updated annually and therefore the distorted signal only exists within years"*[15],

In our view this raises questions with regards to the suitability of the modelling to claim long term benefits based on the use of current data to produce future outcomes when NERA acknowledges that data is reviewed and updated annually. It also fails to acknowledge AEMO's ongoing review and improvement process in the methodology for the calculation of annual transmission loss factors.

Not only does the proposed reform add risk and uncertainty to generator contracting and retail hedging, a move to dynamic loss factors is a significant change to retailers' billing calculations and therefore billing systems. This costly change would it increase the complexity of billing, forecasting and reconciliation and it would materially reduce the transparency of energy costs to customers. It is likely that even large, sophisticated customers and their agents will lack the tools to easily validate energy costs with dynamic losses. We see the added complexity of dynamic losses as a backward step for bill transparency to the customer.

Significant changes to AEMO and participants' bidding systems would also be required to move from the current system of lodging bids at the regional reference node (RRN) to bids at generator nodes as it is unclear that a move to dynamic losses could be accommodated using the current bidding to the RRN framework.

Wealth transfers

Higher hedging costs of retailers will likely erode any reduction in wholesale prices and TUOS offset, leading to an increase in customers' bills from the reform.

Despite NERA's modelling, we challenge the level of asserted benefits that will accrue to customers in real life implementation of the proposed reforms. The NERA report predicts significant wealth transfers from the reform, stemming from competition related factors and congestion rent shifting in the spot market from generators to consumers who pay only for the locational value of generation produced. These wealth benefits are negligible until 2035 and then climb in the final five years with an increase in investment[16]. The modelling assumes that customers received the benefit of reduced wholesale prices, with all reductions in system costs ultimately accruing to consumers.[17]

We have concerns to the level of NERA's modelling of wealth transfers and consider the analysis has significantly overestimated the benefits to customers due to NERA:

---

[14] NERA Cost Benefit Analysis of Access Reform: Modelling Report Page 62

[15] Ibid

16 Wealth transfer from generators of approximately a further $3 billion over the modelling horizon in NPV terms, most of which falls in the final five years of the modelling horizon to 2040. See NERA Cost Benefit Analysis of Access Reform: Modelling Report, 7 September 2020 page 113

[17] Ibid page 112

- assuming that wholesale contract prices remain tied to physical market spot prices and the wholesale contract prices are not adjusted to reflect the costs of purchasing FTR's;
- implicitly assuming that with the exception of forced outages, thermal generators are fully offered to the market at SRMC at all times;
- ignoring the impacts of FTR procurement as an unknown cost added to generation and therefore wholesale pricing, or impacting the contract market with generators potentially passing the price risk through to retailers via hedging to the local node, increasing costs to retailers' customers and large end use customers;
- significantly underestimating the impact of the reform on market liquidity given the change in risk allocation;
- overlooking the impact on retailers, particularly smaller retailers who will face competition barriers given they will face higher hedging costs, being forced to take on the generator's locational price risk. This may provide a competitive advantage to larger dominant players and be detrimental to customer choice;
- not factoring into their analysis, the implementation of REZs, including the transmission investment in shared network capacity that will be undertaken to support REZ's as well as the up to date information on ISP projects; and
- overlooking assumptions around customers' billing impact. NERA assumes significant TUOS reductions are passed through to customers as a result of the auctioning of FTR's at "fair value," however this is predicated on an assumption of levels of network congestion based on minimal new intra-regional transmission investment to maintain pricing differentials between generator LMP's and the RRP (VWAP). Where transmission developments reduce congestion the level of the "fair price" for FTRs reduces, potentially to zero. This reduces the level of TUOS reductions to consumers.

Impact to Liquidity

We have serious concerns that the reforms will be detrimental to market liquidity and NERA has not considered liquidity from a retailer's view of forward contracting. We suspect the reason that NERA found "no evidence that liquidity of hedging products is likely to fall following the implementation of Access Reform[18] is because they considered liquidity through the lens of a contracted generators' bidding incentive for physical dispatch at SRMC but failed to consider liquidity from a retailer's perspective and the requirements of hedging for retail provision to customers. NERA has ignored the prospect of generators, faced with new basis risk, selling wholesale contracts at their local node, and effectively passing the basis risk to retailers. Retailers, now the assumed risk managers of LMP risk, will face higher hedging costs ultimately impacting retail prices and significantly eroding any wealth benefits. These impacts to retailers and retail costs were not explored by NERA.

Alternatively, generators will adjust hedging levels, reducing the level of contracts hedged at the RRN. This adjustment will flow through in both bidding and unit commitment strategy with lower hedged generators focussed on reducing both fixed and variable operating costs and maximising returns from the spot market.

We also consider that NERA has not fully appreciated the impact of FTRs availability and firmness on the existing contract market and hence market liquidity. The allocation of FTRs will be made available on a conservative estimate of transmission network capacity (it is estimated that simultaneous feasibility auction calculation will limit the FTR allocation to approximately 80% of the underlying physical network capacity to allow for planned and unplanned network outages).This will limit the amount of FTR's available to back hedging contracts and hence maintain the current levels of liquidity in the market. This was also not fully explored by NERA.

[18] Ibid page vi

Impact to competition

ERM Power firmly rejects NERA's assertions that the reforms will have a positive impact on competition. Retailers manage market risk through the contract market but will now need to back derivative products with a FTR, with the underlying settlement reference price being the LMP (generator's local price). Retailers portfolio risk management requires deep and liquid markets and flexibility to manage the risks presented but will now need to align hedging to auction outcomes or the availability and suitability of FTR trades on any secondary market. Smaller retailers, who are unable to manage the risk with a vertical integrated structure, will face greater barriers with higher hedging costs. NERA's assessment on liquidity impacts and that the incentive for generators to hedge does not significantly decrease after the reform relative to the No Reform world[19] offers no consideration to firmness, FTR availability, and ignores retailer impacts.

Whilst we acknowledge that theoretically, the availability of FTRs can facilitate expansion of retailer competition between NEM regions via the hedging of inter-regional price risk, the actual overall quantity of FTR's remains finite for a given level of transmission infrastructure, therefore any increase in firmness of inter-regional hedges only occurs via a reduction in available intra-regional hedging capability. SRAs can accommodate this inter-regional hedging now and contrary to NERA's assertions, can be effective (at least subject to the same congestion and outage limitations are the proposed FTR instrument). We caution against NERA's assumed competition benefits when the impacts of higher hedging costs will greatly outweigh the supposed superiority of FTRs as a tool for market entry, over current arrangements.

REZ data and ISP considerations

In its analysis, we note that NERA has sought to only include specific ISP projects – Group 1 and Group 2 projects from the Draft 2020 ISP and has not included 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 Draft ISP project plan only and without the inclusion of the necessary supplementary transmission investment required to support these network augmentations. We suggest that this may have skewed results overestimating the costs of the Non-Reform case.

NERA's costs estimate lack rigor and appear to vastly underestimate costs. We understand the AEMC considers that further work is required to fully appreciate the costs that this reform will impose on the industry and investment pipeline.

NERA's costs estimate purely focus on AEMO system costs and participants' recontracting costs. In our view, NERA has not sufficiently considered the transitional impacts of the reform when calculating costs and should have allowed for wholesale hedging costs impacts to retailers and ultimately customers.

Whilst the AEMC points to further analysis that will be undertaken into participants' system costs, we are already circumspect at the estimates of AEMO system costs, given that historically AEMO costs of reform have been found to be underestimated. This was clearly demonstrated for the Five-Minute Settlement reform where recent expected

[19] Ibid page 84

costs estimates differ greatly to AEMOs estimates during the rule change consultation[20]. AEMO have yet to confirm if the Reform can be effectively provided using the current NEM dispatch engine or if a new dispatch engine, potentially a new full network model may be required to implement all proposed features of the reform.

ERM Power regards NERA's initial cost estimates of reopening long-term duration contracts (PPAs) at an average cost of between $5k and $20k per PPA, or lower, to be extremely optimistic. We see that a change to the underlying reference price (to VWAP), introduction of dynamic losses and requirements around FTRs will result in a requirement to renegotiate the majority of wholesale contracts. Impacts to wholesale contracts will be dependent on the achievement of good faith negotiations of parties which will be influenced by the defending of commercial benefits and will likely be tied in lengthy legal processes when counterparties seek to preserve contract value.

It is reasonable to predict that the Reform will result in technical breach of debt default covenants and require some generation investments to require debt to be refinanced and this may place the viability of projects at risk and could even lead to bankruptcies in extreme cases.

We suggest that a better representation of full costs of the reform must appraise the impacts to the wholesale contract market, particularly on retailers being hedged only to the generator's node and consumers who will face higher retail costs. This has been absent from the analysis.

Summary

We consider that NERA's modelling should be treated with extreme caution. We heavily discount the level of net benefits claimed as the results appear contrary to all previous work and analysis and the underlying assumptions used for future transmission investment is not consistent with the planned reinforcement of the transmission network as set out in AEMO planned ISP and network service provides annually transmission planning reports. The model presupposes that the NEM is dysfunctional and the Reform case is extremely efficient, and the model artificially builds a picture to achieve and quantify the desired outcome.

We believe policy decisions makers need to contemplate this proposed regime in the context of whether this major redesign actually addresses the fundamental issues that were to be delivered by CoGaTI. We suggest it is does not and that focus should be placed on other reform developments that are more targeted and offer solutions to the issues at hand such as:

- Improving information that is published by AEMO (such as transparency around connection point locations)
- Further improvements to the RIT-T, as highlighted earlier, including better governance controls, accountability and oversight to network costs estimates and a consideration of customer benefits
- Continuation of refinement to the ISP and development of REZ design with adequate stakeholder input on the checks and balances for approvals

We contend that a complete overhaul of generator settlement pricing and a complex LMP/FTR regime is not required and will cause harm in the transition that is underway. We strongly recommend that jurisdictional decision makers engage their own independent assessment to critique the NERA modelling and the impacts of the proposed regime on investment before there is any further progression of this proposed reform.

[20] According to AEMO Declared NEM Project Consultation Paper, July 2019, the costs for the 5MS Program are estimated to be approximately $121 million over a ten year period, inclusive of both upfront implementation costs and ongoing operational costs .This differed to the AEMO cost estimates in AEMC, Five Minute Settlement, final determination, 28 November 2017, Sydney, page 145 , extrapolated to 10 year estimated of up front and ongoing costs (upper and lower boundary based $30M to $85M).