19 October 2020

Ms Merryn York
Ms Allison Warburton
Mr Charles Popple
Ms Michelle Shepherd

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Lodged electronically: www.aemc.gov.au (EPR0073)

Dear Commissioners

EnergyAustralia
LIGHT THE WAY

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

AEMC — Interim Report: Transmission access reform, updated technical specifications and cost benefit analysis — September 2020

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

The AEMC has now presented a detailed case for its reforms, including a quantification of the customer benefits of switching to nodal pricing. Its latest design proposals reflect a culmination of broad and deep stakeholder consultation on transmission access reform over several years. We agree that the scale of investment in transmission and generation in the coming decades presents both a risk and opportunity in ensuring the NEM evolves along a pathway of least cost to consumers. We are also firmly of the view that truly efficient outcomes cannot be achieved without having cost-reflective pricing across the entire supply chain.

The essence of the COGATI reform proposals is to correct the misalignment between generator value and compensation arising through the RRP design, thus addressing the 'rents' that arise during times of network congestion. This current market design reflects the desire for simplicity and was created at a time where congestion was not a material concern. Its effect is that locational signals for generators are not fully cost-reflective.

The changes proposed by the AEMC essentially revisit this market design feature and the allocation of congestion risk. They are ambitious, with material implementation costs that are still being accurately quantified. The benefits are also subject to considerable uncertainty. While not strictly regarded as an economic benefit, the reforms involve a significant wealth transfer from generators to customers.

In principle we support the desire to ensure generators are paid the 'true' value of their output through the local marginal price. We also agree that allocating congestion risk onto customers is likely to be the least efficient arrangement, given the role of different parties in the supply chain in contributing and being able to respond to congestion risk.

We consider that further work needs to be done to properly explore how this risk allocation, and the ability of generators to manage price risk through FTRs, would play out in practice. Congestion risk is highly complex, and involves the actions of TNSPs and AEMO, as well as generators. The reforms would introduce likely additional costs and distortions on the market that are not captured in NERA's economic modelling. The AEMC places great faith in market participants to forecast and value congestion, and cites overseas markets as examples where FTRs appear to be effective. However the NEM has different physical characteristics to more meshed systems in other markets, and is at the cusp of significant transformation. So while participants in the NEM value the volume risk of congestion now, quantifying additional price risk, to the standard of a 'board level' investment decision, would require specialist technical resources which are unlikely to be equally held across market participants. And even then, the ability of generators to adequately mitigate these risks through locational decisions or FTR purchases would be limited, including because of the practical compromises in the AEMC's reform designs.

We appreciate the AEMC's efforts in exploring the likely cost of its proposed changes. We will provide the AEMC with a supplementary submission on EnergyAustralia's own cost estimates, following from discussions with the AEMC's consultant. Our initial view is that the AEMC's initial estimates are significantly understated. The timeliness and cost of executing significant changes to participant and market systems will depend on other changes arising between now and the AEMC's proposed 'go-live' date.

The combination of the above observations suggests that the costs and benefits of reforms are more finely balanced than presented in the AEMC's latest report. The timing of benefits is also important to understand. The AEMC states that benefits would accrue in line with the rate of change in the market, and recommend reforms are in place sooner to give the industry time to prepare for change. NERA's modelling suggests the benefits from improved locational price signals and associated price impacts for customers would accrue mainly from the 2030s. The benefits from addressing disorderly bidding would be captured immediately but are not as large, and yet NERA's estimates are several orders of magnitude above earlier independent estimates, which should give pause for further examination.

We acknowledge that the AEMC has been consulting on transmission access reform, including at the request of COAG, for some time. We still question whether the current set of reforms should be pursued now as part of the ESB's broader market redesign program. Our view is that priority should be given to reforms that will ensure the market can deliver new and timely investment. Reforms aimed at other elements of the market, which would encompass things like disorderly bidding, are currently less important and could be sequenced later to ensure priority changes can be properly executed.

The COGATI reforms also no longer directly address the allocation of risk and cost relating to transmission investment coordination. As we recommend below, this should be revisited. The AEMC intends that improved locational price signals ensure generators make the 'correct' location decision. They do not safeguard customers from having to fund any unnecessary transmission investment — the AEMC effectively presumes that, in a world of locational pricing signals, all transmission augmentations to meet any new generation capacity will be efficient.

The AEMC will consult on further detailed aspects of its reforms before making final recommendations to COAG. As part of this consultation, we recommend it:

- conduct further detailed **analysis of 'real life' pricing situations**, integrating decisions around the valuation and purchase of FTRs with respect to example historic and likely future instances of congestion. This will also assist the AEMC in considering parameters for transitional arrangements.

- examine its proposals in **full view of the REZ development frameworks** currently being consulted on by the ESB. FTRs or some similar contractual arrangements may be a complement to REZ developments. The benefits arising from more efficient locational investment appear concentrated on solar PV which suggest that REZs and other planning arrangements, rather than nodal pricing across the entire NEM, could allow a more targeted and effective solution. Pending the ESB's timeframes for consulting on 'Stage two' of its REZ frameworks, this may require only a short and acceptable delay in the AEMC's work.

- further work should be done to examine **whether these reforms should be prioritised** as part of the ESB's other market design initiatives, including how they might change incentives on generators' investment decisions arising from new revenue streams. Notably, the large transfer of wealth from generators to customers, and of risk onto generators, would potentially conflict with the desire to offer new revenue streams from essential services and potentially capacity. It may be the case that other MDIs also affect locational signals and dispatch efficiency.

- reconsider the 'limb' of COGATI relating to **firm generator access arrangements**. We note this has been dismissed given prior concerns about how feasible this would be in practice. However, the ISP's development pathway for 'Actionable' projects and government announcements around project timings suggest a bias towards transmission build to deal with the risk of large capacity closures and to accommodate large amounts of VRE. This might justify revising access and charging models that involve generators directly bearing the cost and risk of transmission investment, rather than indirect incentives relying on congestion pricing.

- As we and others have submitted to the AEMC in the past, we consider that a large portion of benefits identified by the AEMC, in terms of **race to the floor bidding, could be delivered via cheaper and simpler alternatives**, including direct changes to 'tie breaker' rules that give rise to such bidding in the first place. While not as strong as the signals arising from LMPs, improved information on existing congestion could also help work towards the same outcomes.

If you would like to discuss this submission, please contact Lawrence Irlam, Regulatory Affairs Leader (acting), on 03 8628 1655 or Lawrence.irlam@energyaustralia.com.au.

Regards

Ross Edwards
Markets Executive

Summary of the problems to be addressed by the current COGATI design

Nodal pricing provides better locational signals than current pricing based on RRPs. This is not a controversial finding.

The RRP model in the presence of constraints creates an incentive for disorderly ('race to the floor') bidding. This leads to inefficient plant operation (i.e. dispatch out of merit order) and higher costs for consumers.

Congestion also gives rise to volume risk. Currently generators are not fully exposed to this risk and can only manage it in making locational decisions. Because the signals regarding the cost of congestion are weak or not fully borne by the generators that cause it, the concern is that inefficient generation location decisions, once sunk, will leave to TNSPs finding it efficient to build out any associated constraints. Overall, there is a risk to consumers of more transmission investment, plus inefficiencies from total higher system cost.

Static MLFs also provide a weaker price signal of real time costs than dynamic ones.

All taken together, the presence of distorted or inappropriate short run signals affect bidding behaviour and locational decision making for generators. This leads to overall a suboptimal system design and operation.

NERA's calculation of reform benefits requires further validation

NERA's modelling indicates the potential gains in terms of improving price signals for congestion management may be significant:

- **Better plant location and utilisation** - the longer-term impact of applying correct price signals would be to discourage 'winner takes all' type investment decisions with respect to location, improving overall plant utilisation. NERA calculates the reforms would see around 20 GW of inefficient investment (almost all solar PV) being avoided. NERA's point estimate of benefits is $1,738 million in NPV terms out to 2040.

- **Correction of disorderly bidding** – as generators are no longer incentivised to bid at the floor price in the presence of constraints (as they would no longer be paid the RRP) NERA finds that benefits arise mostly where higher cost coal plant would bid at SRMC and so be dispatched in appropriate merit order. Benefits in the order of $800 million to $1 billion are expected over the period to 2040, with annual benefits declining over time as coal exits the system.

NERA's calculation of efficiencies in plant location and utilisation reflect a static calculation of the 'subsidy' arising from price spreads under the 'no-reform' option. This subsidy is deducted from plant capital costs which are used as inputs for the 'reform' scenario modelling. However the 'no reform' model constrains the amount of new transmission investment, which is unrealistic and overstates congestion, thus overstating the value of the 'subsidy' accruing to generators. As raised with AEMC staff, the lack of a 'feedback loop' between the models i.e. rather than use a static value of the subsidy, having this decline in value over time and with new investment, is likely to materially overstate the benefits of reform. Noting there are other aspects of the modelling that understate benefits, and the difficulties in correcting this particular issue within the modelling, this is worth exploring further and highlights one aspect of the modelling's limitations in capturing real life investment dynamics.

The scale of investment savings, namely 20GW by 2040, or around 20 percent of total NEM installed capacity, seems implausibly large on face value given a 'no reform' scenario would still have the timing and volume of generation investment being tied to 'optimal' ISP and REZ planning arrangements, rather than being unconstrained as it has been to date. This scale should also be taken in the context of known issues arising in the NEM for example renewables investment in north-western Victoria and now arising in parts of Queensland. The modelled benefits accrue mainly from the late 2030s and are therefore highly dependent on many other assumptions about the future state of the NEM.

NERA's valuation of the benefits of correcting disorderly bidding, up to $1 billion, compares to $18.6 million calculated previously by ROAM Consulting in 2013.[1] While the calculations are based on different input data and methodologies, such a large divergence warrants closer scrutiny and again highlights the need for caution in relying too heavily on least cost modelling exercises. While we have not reviewed historic data ourselves, comments raised in working group discussions suggested disorderly bidding costs about $20 million per annum currently[2], and the AEMC should use historic data to test the plausibility of forecasts.

NERA calculate that the additional introduction of dynamic marginal loss factors would deliver further benefits of $661 million. However, this does not appear to be integral to the move to nodal pricing, and if assessed on a stand-alone basis would not be justified. The AEMC's decision to include it in the COGATI reforms appears to be that, given the significant changes involved in moving to nodal pricing, and particularly dispatch/ IT systems, the incremental cost of incorporating dynamic marginal loss factors is small. We note that, like LMPs, more cost-reflective signals regarding losses would promote more efficient outcomes so we support these in-principle.

While NERA's approach to assessing competition impacts of the reforms is sound, the values calculated (ranging from zero up to $209 million in benefits) are effectively assumed. As outlined below, more resourced or sophisticated participants will have better ability to cope with the complexity of changes and so the reforms are as likely to be detrimental to competition as beneficial. The AEMC has also indicated the need to explore market power arising from splitting the market into LMPs and we support this further consideration, which should also extend to cover FTRs and financial markets as outlined below. In any case, improving the current state of competition under the current arrangements is not an objective of the reforms, but is something that may flow from the reforms.

The transitional impact of reforms is not yet clear but likely to be significant and negative

Something that falls outside of NERA's modelling is the AEMC's proposals around transitional arrangements. The AEMC recognises that its reforms will have a material and negative impact on generators that have already made investment decisions in expectation of costs, risk and revenues flowing from the current RRP arrangements. It has explored various options to address this, notably by setting out several guiding principles:

- generators should receive the same compensation or expected revenues that might have been earned from the market in the absence of reforms
- investors would generally expect some degree of market reform and other unexpected events over the life of their assets, and that the access reforms have been discussed for several years in various guises

[1] https://www.aemc.gov.au/sites/default/files/content/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks-Review.PDF. See pages 53 and 54, the value of $18.6 million presumes a 5 per cent transmission outage rate.
[2] Grid access reform (COGATI) review – technical working group #8, minutes of 18 June 2020, p. 5.

- the need to balance the interests of incumbent generators against new generators exposed to the full range of reforms, and the interests of consumers, the concern being that transitional provisions could unduly protect incumbent generators or delay reform benefits.

In dealing with the transitional impact of reforms the AEMC effectively needs to set various parameters that would deliver 'fair' outcomes in light of its guiding principles. These parameters include:

- which participants are eligible to receive transitional FTRs
- the volume of FTRs to allocate
- how to allocate FTRs between eligible participants, with further options on using historic data or forecasts to determine this allocation
- the duration of these FTRs, including the proposal to 'sculpt' (i.e. decrease) the volume of FTRs over time
- how and to what extent FTRs will be funded or 'firm', given they will be allocated 'for free' to existing generators and not paid for at auction.

The AEMC's principles are sound, however it will be challenging to translate this into practical steps or parameters that would minimise transitional risk for the market as a whole. The AEMC should be guided by, and release information that illustrates, which incumbent generators are likely to be impacted over the likely transitional period, and how much, in light of different options under consideration. This would inform consideration of matters such as balancing the interests of incumbent generators against new entrants.

As we expand on below, modelling of revenue impacts for participants as it relates to congestion risk and the holding of FTRs (to determine transitional provisions that result in revenue neutrality), is likely to be extremely difficult. The degree of firmness of transitional FTRs, noting they will not be backed by auction revenues, will likely be a key concern. For these reasons we suggest a longer transitional period, of 10 years, may be appropriate.

We also request the AEMC provide absolute clarity on eligibility for transitional FTRs. Of the options presented in its recent report, our preference is for eligibility to be defined as assets that have reached financial close by the date the final rules are made.

The proposed reforms could increase long-term risk given real, imperfect markets

We acknowledge the additional work of the AEMC and NERA in exploring how the reforms will change the nature of risks faced by participants. The following sections outlines some areas where we disagree with the AEMC, and raise matters for further attention.

In summary, the inherent complexities in understanding congestion risk, and practical compromises the AEMC must make in terms of FTR auction designs, will result in divergences from the theoretical outcomes expected of FTRs as a hedging instrument, and may also impact on forward contract markets. It may be the case that these drawbacks do not outweigh the overall net benefit case for progressing reforms, but the scale of costs and benefits at stake justifies further careful consideration.

'First principles' and empirical examination of risk

NERA's earlier examination of whether the reforms increase systematic risk may have benefitted from a more fulsome 'first principles' assessment on how returns associated with a particular activity are correlated with market returns, and how this might change under the reforms. Such an assessment typically[3] involves consideration of factors such as:

- the extent to which the volume of sales / revenue of the activity is associated with movements in the market overall, and the factors that would cause this association to increase or decrease
- the extent of capital intensity of the activity and, related to this, the extent of operating leverage
- the extent to which the activity in question may have market power and the nature of any regulation that may apply where such power exists
- the commercial arrangements for the supply of the relevant goods or services, including the nature of any contracting that is entered into with purchasers and the nature of the charges that are applied for the services.

NERA's analysis of relevant factors affecting systematic risk is as follows:

> To determine the precise impact would require examination of the market correlation of the constraint risks, and basis risk, based on modelled electricity prices and historical market returns. However, in theory, we expect that the constraint risks and basis risks would not be strongly correlated with the market return. The market return is driven by macroeconomic variables such as aggregate economic growth, and reflects long-term expectation. In contrast, the constraint risk and basis risks are determined by variations in local electricity prices, which in theory would not be strongly correlated with movement in market's expected return. Therefore, while this is an empirical question, conceptually we would not expect any material impact on cost of equity as a result of access reform.[4]

As explored further below, the COGATI reforms may reduce generator willingness to contract forward, thus causing returns to fluctuate more closely in line with general market drivers.

Aside from theoretical or first principles assessments, we note the AEMC has been presented with substantial commentary from market participants that its reforms will materially increase their cost of capital. While this may reflect self-interest, it would be bold for the AEMC to refute this entirely on the basis of NERA's modelling, which is based on many simplifying assumptions and qualifications. That the AEMC may place more weight on the views of consultants rather than real market evidence could itself undermine confidence in its decision making and increase perceived risk.

The reforms will involve a new level of complexity in valuing congestion

The AEMC has effectively assumed that it will be more efficient for generators to bear the entire risk of congestion rather than customers, even though generators are not entirely able to manage or respond to this risk. Furthermore, it assumes that generators will still be able

[3] See Martin T. Lally (2000), *The cost of equity capital and its estimation*, Volume 3 in T.J. Brailsford and R.W. Faff (Eds.), McGraw Hill Companies Inc., (Sydney).

[4] NERA, *Costs and Benefits of Access Reform – Prepared for the Australian Energy Market Commission*, 9 March 2020, p. 87.

to place a value on this risk and FTR arrangements will allow them to perfectly hedge price risk.

The AEMC's general principle is that all constraints in NEMDE get put into LMPs. This is largely on the basis of ensuring that settlement residues and FTR payouts are aligned. This does, however, add new levels of complexity and the prospects of windfall losses (and gains) for generators for events beyond their control.

At present, sophisticated load flow modelling typically examines thermal constraints which inform investment and operational decisions. This type of constraint is largely what the AEMC and many stakeholders have in mind in terms of managing generators that inefficiently 'crowd' into parts of the network without appropriate locational signals. These types of constraints are also easier to model from historic data.

However AEMO constrains units off for a variety of reasons – this can be somewhat arbitrary and very unexpected. This can pose a problem for thermal generators who, in responding to AEMO actions, take time to reach zero output. Under the COGATI reforms, these generators would be exposed to negative LMPs for some time and an associated penalty. Generators would similarly be exposed to windfall losses during times when AEMO / TNSPs need to reclassify contingencies for bushfires or lightning, or on loss of a network element.

A true efficient allocation of risk would involve costs being borne by the TNSP and AEMO as system operator. We note the AEMC's suggested amendments to the STPIS, as well as suggestions to improve outage notifications, would address this point to some extent.

Whilst thermal constraints are generally well understood and able to be forecast, we have seen in recent years and increasingly going forward, other more complicated constraints impacting the system, which even AEMO and TNSPs with full knowledge of network topography, connecting proponents and PSCAD etc modelling, have at times introduced with little or no forewarning (which would make hedging with an FTR nigh on impossible):

- SA system strength constraint limiting aggregate output of inverter-connected generation in the state
- West Murray/north-west Victorian generators faced months of limits to total inverters online due to unstable responses to voltage changes
- Northern Queensland system strength limits with large binary outcomes for small changes in local demand
- recent material changes to prominent voltage stability limits in southern NSW and additional erosion of this limit during nearby line outages.

These different dimensions play into how a participant must deal with new pricing risk under the reforms. While participants currently examine the nature of congestion and impacts on their plant, the added layer of price risk makes it more complicated in terms of how to value constraints. FTRs will be released periodically at auction with respect to a 'snapshot' of the NEM. The valuation for a particular FTR could encompass a wide variety of constraints, participation factors for each participant in that part of the network, etc many years into the future. Bidders would be seeking particular FTRs for different reasons. This presents a fungibility issue as well.

The AEMC cites the operation of LMPs and FTRs in overseas markets as well functioning and models that could be adopted in Australia. It should further explore whether the NEM is comparable in terms of congestion risk (e.g. overseas grids tend to be more meshed), whether system operators and transmission owners bear some of this risk and whether all constraints are covered by FTRs.

Barriers to entry and competition issues associated with FTR auctions

NERA and the AEMC place great faith in the efficient operation of FTR markets to ensure that they are traded at fair value and, critically, that the prices paid for FTRs reflect their expected payout value. It is essentially assumed that each participant can perfectly value congestion/ basis risk, and can obtain sufficient FTRs, at this value, if they wish. This includes the role of non-physical participants and of secondary markets to produce derivatives that suit the need of individual generators.

The AEMC has given some consideration to concerns around 'hoarding' of FTRs, finding these were unfounded because:

- barriers to entry do not appear to be high. Notably, the FTR 'market' encompasses multiple FTR routes given auction design, such that parties bidding for separate routes are effectively competing with one another
- the AEMC is not aware of this being a particular concern in international FTR markets, and noted the absence of specific FTR mitigation measures for hoarding
- physical dispatch is not directly impacted by the inability of generators to get access to congestion management tools.

NERA's modelling did not illustrate how FTR purchases and allocations, including transitional allocations, might work in practice. It did, however, discuss the issue of who holds FTRs and when they are purchased, in the context of incentives to hedge and general contract liquidity:

> We find that whilst the incentive to hedge for generators holding an FTR is unlikely to be significantly impacted by the reform, the incentives to hedge for generators who do not own an FTR (in the LMP world) are likely to fall. In our analysis, we do not distinguish how far ahead of delivery forward products are bought and instead assume that all generators have access to a quarterly baseload CfD at a strike price that reflects the average RRN price for the quarter. Moreover, in order to interpret our analysis that contract market liquidity will not worsen under the FTR world, one must assume that generators own an FTR at the point they purchase forward hedges.[5]
>
> We have no test for the simultaneous feasibility of FTRs in our analysis. In reality, the volume of FTRs available will be less than the transmission capacity in order to increase the likelihood that settlement residues are sufficient to ensure FTR pay-outs are firm.
>
> Therefore, it may be possible that actual FTR ownership is less than would be required to facilitate optimal hedging by generators. Consequently, some generators may be dissuaded from hedging forward because they are unable to access FTRs. In other words, some generators may find that some of their generation capacity faces the risks

[5] NERA, *Cost Benefit Analysis of Access Reform: Modelling Report - Prepared for the Australian Energy Market Commission*, 7 September 2020, pp. 81-82.

> in the LMP world rather than the FTR world which, according to our analysis, results in lower incentives to hedge.
>
> Whilst simultaneous feasibility constraints apply to primary market FTRs sold through auction and backed by settlement residue, participants may be able to purchase FTRs on the secondary market, subject to being able to find a willing counter-party. If the secondary market for FTRs is sufficiently liquid, all generators may be able to purchase as many FTRs as they need at fair market prices.

The functioning of FTR markets and the pricing of congestion risk appears to be critical and worthy of further exploration. The issue of 'hoarding' is one element of this. In terms of the specific points made by the AEMC about hoarding:

- the grouping of FTR routes and of associated bidders does not have a bearing on barriers to entry or efficient market operation in terms of the complexity of valuing congestion risk
- the absence of concerns and mitigation measures in international markets could mean that longer-term dynamic effects are difficult to ascertain, or that, rather than being a market power concern, there is an added fixed cost or risk premia associated with more sophisticated congestion management that is needed under a 'normal' FTR/ LMP design
- we recognise the separation of physical dispatch from financial/ congestion management tools. However, the concern we are raising is the inability of generators to access congestion management tools in a way that accords with the AEMC's and NERA's modelling of the market. That is, overall risk increases and investment in efficient generation is subdued.

We expect that the complexity involved in valuing and procuring FTRs will favour the largest and more resourced investors. The AEMC has heard stakeholder feedback regarding the complexity involved in its reforms, and has spent considerable resources in commissioning NERA to create a nodal model of the NEM. The analysis required by market participants in securing finance and investment approvals would be far more complex than this, requiring limited and specialised resources. The AEMC will be gathering information on implementation costs and in doing so needs to recognise that these costs can actually represent real barriers to entry for smaller physical participants.

Aside from cost barriers, the prospects of hoarding by speculating entities would result in the leakage of rents that are intended to flow from generators to customers under the COGATI reform design. That is, generators would be unable to cover themselves for price risk, and FTR payouts would accrue to speculators.

The complexities associated with valuing congestion risk could manifest as higher prices paid by customers in several ways:

- the inability of generators to secure FTRs at all
- the inability to secure FTRs that are completely firm
- paying risk premia for FTRs where participants are risk averse
- paying more than fair value where congestion risk is not adequately understood

- the potential misalignment between FTRs at auction – the AEMC proposes quarterly swaps and time of use FTRs – and the output profiles of wind and solar generation.

Some of these factors are made worse by the scale of investment taking place in the coming decades and the growing complexity of the NEM. Some generators will require FTRs to achieve financial close, well ahead of real time dispatch and so a better understanding of the conditions that give rise to congestion.

Financial market liquidity

As noted above, NERA's analysis examined the propensity of participants to forward contract given their ability to manage congestion risk, finding that overall risks are unlikely to be materially different under the COGATI reforms.

Further consideration should be given to how financial markets and contracting might be affected where contracting and settlement takes place across potentially hundreds of pricing nodes. That is, forward contract markets are currently concentrated on several regional nodes, and moving away from this means that contracts may become less visible, more bespoke and with less efficient price discovery. This is essentially the corollary of the AEMC's earlier consideration of the abolition of the Snowy region:

> Under the Abolition proposal, Snowy Hydro's Murray and Tumut generation are able to offer contracts at the Victorian and NSW RRNs, without the risk of price separation, reducing its basis risk compared to the alternatives…
>
> The Commission expects that the reduction in basis risk under the Abolition proposal is likely to improve Snowy Hydro's incentives to offer more competitively priced contracts at the NSW and Victorian RRNs compared to the alternatives. This, in turn, will increase pressure on other parties to be similarly competitive. Several submissions supported the conclusion that a reduction in Snowy Hydro's basis risk under the Abolition proposal would encourage Snowy Hydro to offer more competitive contracts, resulting in lower contract prices, with flow-on benefits for the liquidity in the contract market, inter-regional trade.[6]

This is similar to our earlier points about the introduction of LMPs and FTRs creating a need for more complex risk management, but in this sense, arising between generator revenues and retailer costs.

Other costs and risks associated with congestion risk management/ firmness etc

The expected scale of funding flows is a critical issue and requires further consideration. The AEMC has thoroughly examined concerns about the 'firmness' of FTRs and has responded in its proposed design elements, for example, moving to a VWAP. NERA also examined two case studies in its latest report examining revenue sufficiency relating to recent line outages.

Large flows to and from settlement residue are likely to result in significant revenue variations for all involved (generators, TNSPs, customers). The AEMC's analysis and FTR designs suggest that this should be at least revenue neutral in theory, however the purchase, payout and funding of FTRs will result in material costs for working capital and likely impact on prudential requirements for some participants. NERA acknowledged this in its modelling of revenue volatility but considered it not to be relevant:

[6] AEMC, *National Electricity Amendment (Abolition of Snowy Region) Rule 2007*, Rule Determination, 30 August 2007, p. 22. https://www.aemc.gov.au/rule-changes/abolition-of-snowy-region

For simplicity, we do not include the price of the contract (which is fixed and does not affect volatility of cashflows) nor collateral posting.[7]

Carrying costs associated with FTR purchases may also be material, noting some participants have expressed the wish to purchase FTRs at auction up to 10 years in advance.

As per our prior consultation feedback, and to some extent acknowledged by the AEMC, FTRs will not provide full coverage of pricing or basis risk. Uncertainty regarding future exposure, arising from a lack of firmness or from an inability to secure FTRs, will attract either a risk premium in financial contracting or lead to reduced number of financial contract offers, both of which will drive an increase in wholesale prices. As raised in working group discussions, firmness concerns mostly arise from the need to forecast network physical characteristics up to 10 years ahead of time to suit auctions, and the risk of FTR allocations in initial auction rounds over-representing the system capacity due to new emerging constraints, environmental factors and general network expansion.

The AEMC should explore how its COGATI proposals might be prioritised and interact with the ESB's broader 2025 market redesign

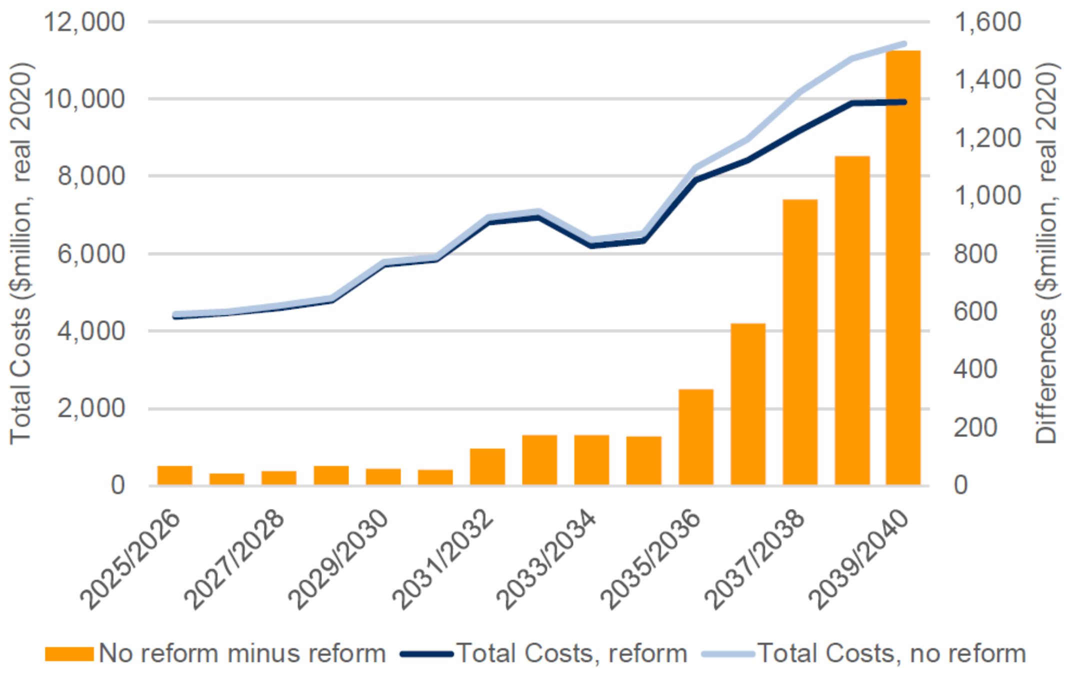
We acknowledge that the AEMC has been consulting on transmission access reform, including at the request of COAG, for some time. We still question whether the current set of reforms should be pursued now as part of the ESB's broader market redesign program. As discussed further in our separate submission to the ESB, our view is that priority should be given to reforms that will ensure the market can deliver new and timely investment. Reforms aimed at other elements of the market, such as those that improve market operation and short-term decisions, are currently less important and could be sequenced later to ensure priority changes can be properly executed.

The combination of the above observations suggests that the costs and benefits of reforms are more finely balanced than presented in the AEMC's latest report. We note the AEMC has emphasised that benefits would accrue in line with the rate of change in the NEM.[8] While NERA's modelling could be further refined, it suggests the bulk of benefits from improved locational price signals and associated price impacts for customers would accrue from the 2030s. NERA's charts below suggest cost savings of around $100 million per year from 2030 would accompany roughly a $2/MWh difference in the GWAP. This would increase significantly from around 2036-37.

[7] NERA, September 2020, p. 68.

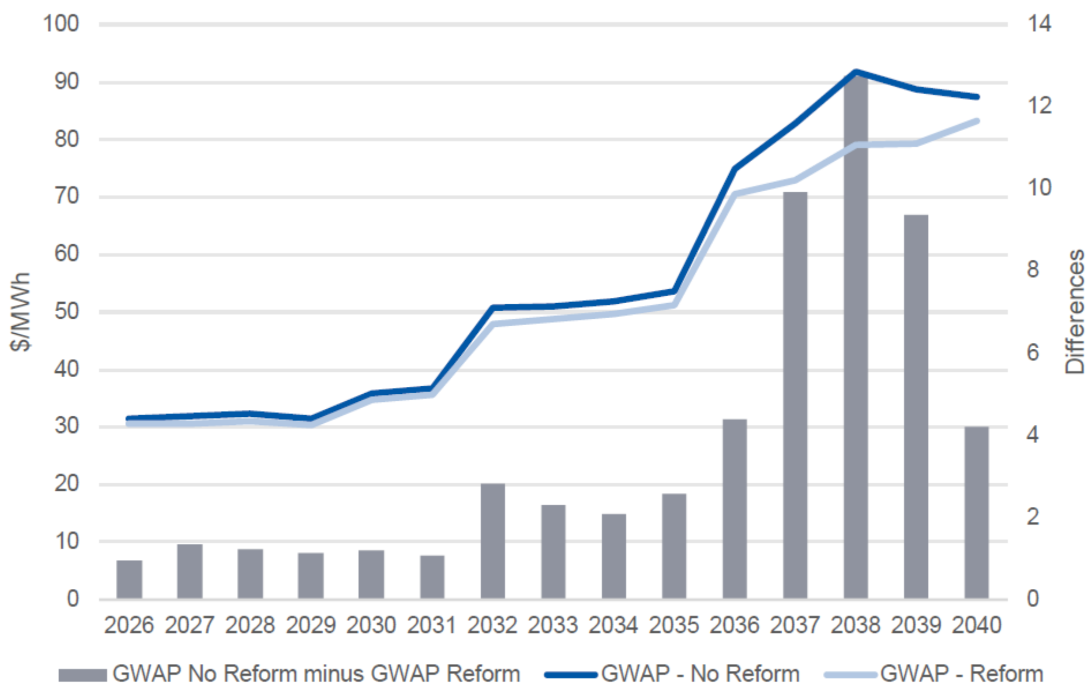
[8] AEMC, *Transmission Access Reform: updated technical specifications and cost-benefit analysis*, Interim report, 7 September 2020, p. iii.

Figure 3.13: Total Cost Differences Between No-Reform and Reform Case Increase at the End of the Horizon



Source: NERA.

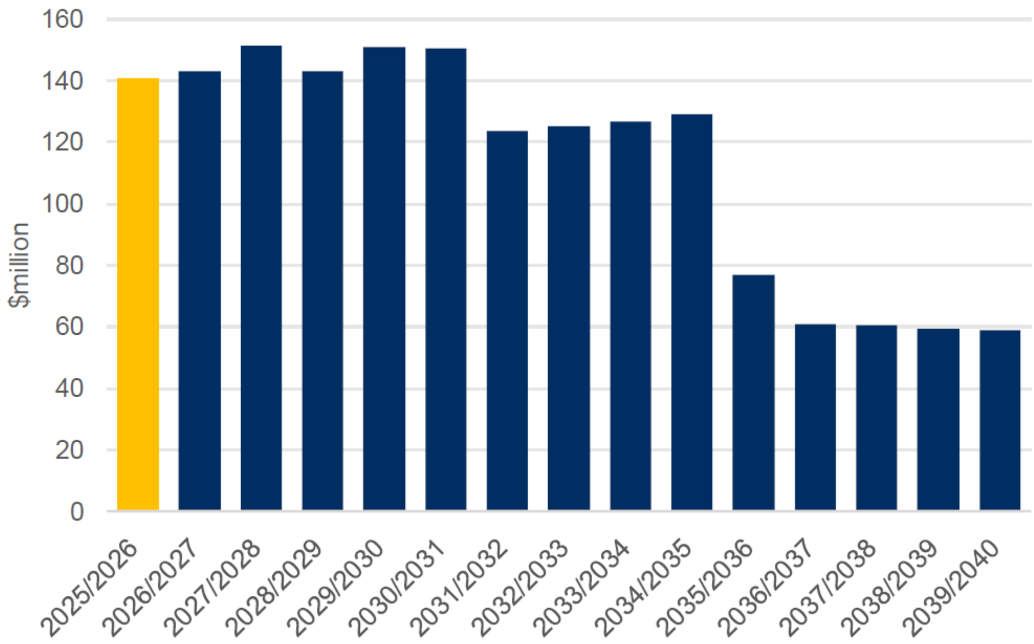
Figure 3.12: GWAP Differentials between No-Reform and Reform Case



Source: NERA.

The benefits calculated from addressing disorderly bidding would be captured immediately. The inference from the charts above on investment benefits suggest the correction of disorderly bidding from today would translate into around $2/MWh of GWAP. We note that NERA's estimated benefits are several orders of magnitude above earlier independent estimates and suggestions of historical cost estimates, and should be subject to further validation.

Figure 5.4: Evolution of Benefits from Eliminating Race to the Floor Over Time (Lower Bound)



Source: NERA.

The COGATI reforms would involve a material transfer of wealth from generators to consumers, and a shift in risk from consumers to generators. While this aligns with the desire to provide more efficient and cost reflective signals, it should be considered in the context of the scale of investment that needs to take place in the NEM. As detailed in our concurrent submission to the ESB, our view is that investment in dispatchable generation and storage require additional incentive mechanisms than in the current energy only market. That is, it is already difficult to commit to a multi-decade payback in the current volatile environment. Adding another layer of uncertainty and costs, recognising these are intended to deter inefficient investment, will increase this difficulty.

The various dynamics we can see arising from NERA's modelled outcomes and broader policy changes are:

- <u>Conflict with renewables incentives</u>: grid-scale wind and solar PV are still being drawn into the market by government renewables targets. This will occur at the same time incumbent VRE investors will get negatively impacted by the transition to COGATI. This effectively makes it more expensive for governments to hit RET targets

- <u>Multiple price signals for firming coal generation</u>: NERA's modelling suggest that existing coal generators will be most affected by the removal of congestion rent arising from defensive bidding. It is not clear how these plant will be affected by the allocation of FTRs, however all else being equal, this will likely accelerate their closure decisions. These and other dispatchable plant would likely be provided new revenue streams in terms of ESS, RAMs etc. The thermal exit MDI is also examining whether large thermal capacity should stay in the system longer. We recognise that the conflicting price signals for these plant may not be as important as ensuring they face the correct signals individually

- <u>Further 'crowding out' of generation and storage</u>: The wealth transfer from generators to customers under COGATI would amplify the negative sentiment towards firming generation and storage arising from AEMO's planning arrangements. The Actionable projects and timings identified in AEMO's 2020 ISP see transmission investment essentially displacing local firming capacity as a complement to increasing VRE penetration. Some governments have also since signalled the willingness to accelerate large transmission augmentations ahead of economically prudent timing. In our view, this stance will lead to consumers paying higher costs than necessary in the form of direct transmission investment, rather than relying on dispatchable generators and storage risking their private capital in the market.

The reforms do not directly prevent customers paying for inefficient transmission

These proposed reforms are heavily geared towards altering incentives on generators. In this way they are agnostic to the transmission development pathway. The AEMC does, however, propose to amend the STPIS to ensure incentives reflect the 'cost of congestion' rather than instances of material congestion. The justification for this change appears to be more directed at stakeholder concerns around transmission outages and 'firming' of FTRs, rather than incentivising or efficiently allocating the cost and risk of transmission investment.

In essence, the AEMC's approach is to presumes that, in a world of locational pricing signals, all transmission augmentations to meet any new generation capacity will be efficient.

There is a risk that the reforms will be ineffective in providing locational signals as intended, given the myriad of other factors affecting generation investment. That is, generation may simply be penalised for its location and unable to respond to this, with an inability to respond to the operational price signal it is receiving.

There are less ambitious but workable alternatives to COGATI

The AEMC has signalled the willingness to take a practical stance towards its reform options, reflecting the trade-off between complexity and the maximisation of theoretical net benefits. This includes:

- its decision to not have unscheduled load to face LMPs, and leaving this optional for scheduled load

- proposing to not have FTRs cover losses

- exploring whether FTRs should only be allocated for pre-defined routes.

We consider that the AEMC should give further consideration of whether other concessions could be made in delivering reform options. Specifically, other options would involve less downside risk and lower costs, while still capturing a material portion of benefits around efficient generation and transmission investment.

Planning outcomes and reforms around REZ access models

The current open access regime does not expose generators to the full extent of congestion risk. As mentioned above, the key concern, reflected in NERA's modelling of benefits, is generators making suboptimal locational decisions, resulting in lower utilisation, likely inefficient transmission build to accommodate these decisions, and higher total system costs as a result.

As many stakeholders have raised, the new 'Actionable' ISP framework, and associated development frameworks supporting REZs identified in the ISP, directly target the prudent and efficient build of network investment to accommodate optimal investments in generation, in terms of the mix, scale and timing of generation plant commissioning. Recent proposals put forward by the ESB obviously post-date the AEMC's earlier COGATI design proposals where the reforms to the access regime were intended to provide the sole solution to the coordination of generation and transmission investment. In short, the need for a market redesign around generator pricing incentives, alongside a centrally planned investment pathway, is less clear.

We note NERA's modelling suggests benefits of around $1.7 billion (around half of the total net benefits from COGATI) from efficient locational decisions and associated dispatch, based on perfect foresight, and importantly the Actionable projects from the 2020 ISP. However, NERA's modelling does not, and could not feasibly, accommodate more detailed decisions affecting generator locations that would arise from REZ planning decisions.

The ESB is currently consulting on Stage One of its REZ reforms, with commercial and funding arrangements in Stage Two yet to be released for comment. It seems prudent for the AEMC and stakeholders to consider the COGATI proposals in full view of possible REZ arrangements to ensure they are as complementary as the AEMC suggests.

'Direct' access models

We note that the 'limb' of COGATI relating to firm generator access arrangements has been dismissed given prior concerns about how feasible this would be in practice. However, the ISP's development pathway and government announcements around project timings to suggest a bias towards transmission build to accommodate risks associated with the exit of large thermal capacity and to accommodate VRE investment. This might justify revising access and charging models that involve generators directly bearing the cost and risk of transmission investment, rather than indirect incentives relying on congestion pricing. It may be that this type of access model is adopted as part of REZ developments.

Access arrangements within each REZ could involve, for example, restrictions around host capacity, similar to current 'do-no-harm' requirements. That is, new build beyond the planned 'efficient' capacity per technology type in a REZ could be blocked or subject to other restrictions.

Disorderly bidding and tie-breaker outcomes

The inefficiencies arising from disorderly bidding arise because generators behind a constraint are treated equally in the event they bid the same floor price. This has two effects:

- generators are dispatched out of merit order

- generators are less exposed to volume risk, which dulls locational decisions and can contributes to 'winner take all' inefficiencies where new generators crowd out incumbents that are cheaper or generate at similar cost.

There must be a simple and direct solution to this problem via re-examining what is effectively a 'pro-rata' dispatch under current tie-breaker rules. Two guiding principles for re-designing tie-breakers would be:

- generators submitting the same bid should be treated differently in proportion to their costs, i.e. lower cost generators get preferential dispatch

- where bid-tied generators have the same cost, those with an earlier commissioning date get preferential dispatch.

NERA's modelling of 'no reform' outcomes suggest that inefficiencies in locational decisions arise mostly because of excessive solar PV investment. Under the above principles, PV generation would still be incentivised to invest in nodes that undercut thermal incumbents, even if the node is already oversupplied. They would, however, be disincentivised to locate in nodes that are already saturated with zero marginal cost plant and would deliver no additional system value or consumer benefit.

As illustrated in NERA's modelling of investment benefits, solar PV is the most sensitive plant type to location, given irradiance is likely to be the key factor driving decisions rather than site-specific factors for other plant type e.g. fuel transport costs, land use competition. Hence relatively small changes in locational incentives via tie-breaking rules may be sufficient to capture benefits ahead of more fundamental changes in the form of LMPs and FTRs.

Specifics of the rules around this would need to consider how to define 'cost'. Alternatively, it can be presumed that wind and solar PV generate at least marginal cost of all generation types, thus rules could be written for the specific treatment of plant type. This would also accommodate combined generation and storage i.e. these combinations behind the generator connection point would be treated differently to 'pure' wind and solar generation.

Improved information for locational decisions

As raised in our prior submission, congestion risks currently borne by generators take the form of being constrained off and/or via changes in their MLFs. We note the AEMC has regarded these signals as insufficient, however it should explore whether information signals regarding investment decisions can or have been improved, by:

- information published as part of the ISP and with connection inquiries[9]

- increasing transparency of new projects.[10]

There are also locational signals coming from new system strength framework that will improve generator locations. Essentially, a connection charge for generators that 'demand' system strength:

[9] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps
[10] https://www.aemc.gov.au/rule-changes/transparency-new-projects

This mechanism would utilise a $/MVA levy on connecting generators, based on the marginal cost of the additional MVA required by the system. It will also include a locational component, to account for the electrical distance from a node (the source of system strength being maintained by the TNSP) to the generator's connection location.

By accounting for available fault level and electrical distance, this charge would send a price signal to generators to further reduce their demand for system strength. Generators would be incentivised to reduce this charge by taking action to either locate closer to the node (reducing their consumption of system strength), or to avoid the charge entirely by obtaining greater capability to require less system strength (i.e. install inverters with grid forming capability).[11]

Better incentives for TNSPs to efficiently manage outages and associated congestion risk

The AEMC proposes that the AER's incentive scheme use LMP information to calculate the market impact component. The outcome of this would be for TNSPs to face a more efficient signal than having the current arrangement where incentive payments are tied to relevant outage events with a market impact of over $10/MWh.

We note that this change can be pursued irrespective of other proposals relating to LMPs and FTRs. More effective valuation of outages and of associated congestion should have the effect of reducing the frequency and duration of network constraints. A volume component should be considered as well although likely difficult to value. For example, an outage that constrains 10MW of energy with a marginal value of $15,000 is very different from one that constrains 1000MW of energy with a marginal value of $15,000.

Other changes canvassed by the AEMC in the name of ultimately 'firming' FTRs should also be pursued to the same effect. This includes measures to ensure TNSPs and AEMO provide more accurate and ideally longer term forecasts of network outages and other network characteristics. This would enable generators to respond with more efficient plant operation, thus avoiding windfall gains and losses arising from 'surprise' congestion.

[11] https://www.aemc.gov.au/sites/default/files/2020-10/System%20strength%20investigation%20-%20final%20report%20-%20for%20publication.pdf, page 31.