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Transmission Access Reform – Consultation Paper

EnergyAustralia (EA) is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. EA owns, contracts, and operates a diversified energy generation portfolio that includes coal, gas, battery storage, demand response, solar, and wind assets. Combined, these assets comprise more than 5,000MW of generation capacity.

EA appreciates the opportunity to comment on the Australian Energy Market Commission's (AEMC) Consultation Paper on transmission access reform (TAR) in the National Electricity Market (NEM). We acknowledge that Energy Ministers have tasked the AEMC with progressing further design work on the hybrid model, building on the proposals from the Energy Security Board and Energy Advisory Panel. We also recognise the AEMC's attempt to make the hybrid model workable for implementation within a narrow timeframe, and appreciate the AEMC's efforts to collaborate and inform industry on its revisions, preferred positions and exploration of new options.

Overall, while we accept that congestion risks may arise in the NEM, including areas around jurisdictional Renewable Energy Zone/s (REZ), we have concluded that the evidence supporting the proposed hybrid model will unlikely deliver net benefits. EA remains very concerned with the ongoing complexity of the proposed hybrid model, especially noting that key problems with the design flagged by industry, including EA over previous consultation, remain largely unaddressed. In our view all of the proposed Priority Access and Congestion Relief Market (CRM) options under consideration have problems that require significant further time and problem solving to determine which design decisions to take with least impact to participants, consumers and market operations. It therefore seems near impossible that these issues (and any new arising issues, especially in the absence of a revised costs and benefits assessment) can be resolved by the end of 2024.

Over the last 18-24 months, several policy developments and regulatory reforms have occurred, which we believe will largely deliver against the TAR objectives. Specifically, the introduction and deployment of jurisdictional Renewable Energy Zone[1] policies and the Federal Capacity Investment Scheme (CIS)[2] respectively seek to explicitly provide for access rights and will support investments that limit network congestion risk and maximise reliability firmness. In developing these policies, we expect that each government would not wish for their projects (i.e. declared REZ or CIS Agreements) to experience ongoing congestion or curtailment risks, and as such have been designed as such to minimise impacts, risks and taxpayer costs.

With regard to REZ policies, the NSW, Queensland and (as of this week) the Victorian Governments[3] have introduced a form of 'closed access' policies to prevent new non-REZ generators from connecting to parts of the grid in their jurisdiction and impacting their REZ investments. Our expectation is that while other NEM jurisdictions have not announced similar policies, they will likely take similar steps themselves in time as their REZ policies are firmed up.

Noting the outstanding TAR issues and these significant government intervention policy developments, EA believes there is sufficient evidence for the AEMC to recommend to Energy Ministers that TAR should not be progressed further. Instead, scarce HR resources at the energy market bodies should be redeployed to other more pressing issues on the regulatory agenda.

However, should Energy Ministers wish to continue to prosecute TAR[4], we consider that a more targeted and simpler policy solution should be explored. We consider the following alternative policy recommendations, either individually or together, offer a less risky and more familiar path forward when compared to the proposed hybrid model. EA encourages the AEMC to consider and explore these option/s further – we are happy to provide more detail as necessary:

- Leverage existing policies like CIS and REZ and defer complex TAR reforms until the post-2030 review has completed.
    - We note that CIS Agreements will be subject to a limited protection change-in-law provision, which only applies to new unforeseen market reforms. Noting that TAR is a 'live' policy proposal, it would not be captured by this CILP and therefore expose CIS agreement holders to bid price risks which cannot be avoided.

[1] Renewable Energy Zones | EnergyCo (nsw.gov.au); Queensland Renewable Energy Zone Roadmap | Department of Energy and Climate; Victorian Renewable Energy Zones; Tasmanian Renewable Energy Zones; Electranet-SE-SA Renewable Energy Zone.pdf (aemo.com.au)
[2] Capacity Investment Scheme - DCCEEW.
[3] Victorian-access-regime-paper.pdf (energy.vic.gov.au)
[4] If the hybrid model is to proceed, PA option 1 and CRM option 1 with settlement at the access RRP is preferred based on our understanding of the options. We do not support a co-optimised CRM.

  - Generally, piecemeal wholesale market interventions will almost certainly create unforeseen and by-design problems which cannot be resolved without acceptance of their real impacts. Instead, we believe that a more holistic approach through the Post 2030 review would be better and could be used to assess the effectiveness of CIS and REZ implementation to determine if inefficient new investment decisions in combination with race to the floor bidding continue to create the growing problems identified by TAR.

- Reconsider the voluntary standalone CRM model proposed by Edify Energy, which does not appear to introduce the complexities of the hybrid model but still reflects long run marginal costs in generator bids.
  - Congestion can lead to curtailment of incumbent renewable energy production, which is not compensated for in CIS agreements. As such generators with CIS agreements, irrespective of their location (although almost all are expected to be located within a REZ), will be exposed to congestion risk. As generators have limited control over congestion (once built) and cannot easily forecast it, we believe a voluntary physical CRM could incentivise congestion relief without the challenges of the priority access options, or two stage-dispatch in the hybrid model.

- Exploring a dynamic (or periodically reviewable) NEM-wide controlled access policy, implemented through existing REZ programs.
  - This approach would leverage established frameworks by jurisdictional governments and implement a common set of rules to protect REZ regions from congestion and/or curtailment risks. The NEM access framework should either be dynamically applied by AEMO on a regular interval basis (to be determined) or subjected to a periodic review - acknowledging that some congestion/curtailment risk is healthy in the system.

Our full submission to the consultation paper is in **Attachment A**.

If you have any questions in relation to this submission, please contact me on 0422 399 181 or at Dan.Mascarenhas@energyaustralia.com.au.

Yours sincerely,

Dan Mascarenhas
Regulatory Affairs Lead

Attachment A

Summary of Position

EA considers that TAR and the hybrid model have notable deficiencies and pressure to achieve the stated objectives can be realised through other policy and regulatory developments. As such, there is no longer a need or desire to progress TAR any further at this stage.

In our view, TAR has several significant issues which remain unresolved –:

- **Investment efficiency**: Existing policies like CIS and REZ can help promote efficient investment decisions for grid upgrades alongside new generation. All of the proposed priority access options can lead to suboptimal locations as a result of rushed connections, and potentially worsen congestion and other system operational risks.

- **Financial Market Risks**: The hybrid model introduces complexities that make it difficult for generators to hedge contracts leading to low contract liquidity. This impact would unlikely enable incumbent retailers to manage their wholesale hedge position nor would it encourage retailer entry.

- **Existing and New PPAs**: The hybrid model's impact on existing and new Power Purchase Agreements (PPAs) will likely raise investment costs, including the cost of capital, in addition to the general application of tighter lending obligations to account for the effects of priority access.

- **Consumer Costs**: The complexities of the hybrid model would lead to higher premiums for both renewable energy investment (via higher CIS bids or PPAs) and electricity prices for consumers (given higher hedging costs). Conversely, if the CRM is underutilized or congestion occurs infrequently, CRM prices could be low, meaning that CIS agreements are called on to meet floor price payments would significantly increase costs for taxpayers.

- **CRM Co-optimised Model Concerns**: The co-optimised model introduces significant complexities, untested risks, and substantial cost increases and should not be progressed. Having the ability for CRM prices to set the regional reference price, would likely force CRM participation, therefore rendering the key benefit of the CRM (i.e. its voluntary nature) unworkable.

- **Outdated Cost-Benefit Analysis**: There are deficiencies in the cost-benefit analysis that should not be overlooked. The cost-benefit analysis doesn't reflect the revised proposals such as co-optimisation and underestimates potential impacts of priority access and congestion relief market frameworks.

We build on our views against each of these points further below.

1.Investment efficiency addressed by existing policy; priority access falls short

The four objectives which underpin the AEMC's work to progress development of the hybrid model are set out below. In our view the hybrid model, comprising PA and a voluntary-in-principle CRM, fails to meet the stated objectives. We discuss each in turn.

> *Objective 1: Investment efficiency: Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, taking into account the impact on overall congestion.*

This objective requires providing long term signals investment in locations that maximise generation and minimise grid congestion.

1.1 Existing policy provides added locational signals for efficient investment

Renewable Energy Zone (REZ) policy, informed by AEMO's Integrated System Plan aims to promote investment efficiency by coordinating development in specific geographic areas with high renewable energy potential. REZs can be valuable tool for optimising variable renewable energy investment. [5] REZ policy brings together communities, network operators, developers and governments in a coordinated planning process which identifies grid limitations within the REZ and seeks to develop a targeted transmission investment plan to address them. There's also the benefit of streamlined environmental and planning approvals within the designated zone, accelerating project timelines.

The CIS design is complementary to REZ policy and together can provide added locational investment signals. Under the CIS, the selection of projects is based on a merit order, encouraging proposals that consider both cost-effectiveness and minimal grid

[5] Optimal Capacity in Renewable Energy Zones (griffith.edu.au).

impact/location.[6] Successful bidders receive long-term contracts, granting developers with predictable revenue streams and encouraging long-term planning.

The combined impact of CIS awarded agreements and REZ coordinated planning processes and streamlined approvals can add locational signals to support efficient investment decisions to address congestion.

However, we acknowledge that even with good planning and technology, congestion can lead to curtailment of renewable energy production. Some congestion risk in the energy system is a good thing and will support maximising network utilisation. But CIS agreements do not address congestion, and generators are fully exposed to this risk. As generators have limited control over congestion and cannot easily forecast it, policy makers must explore how the market can shoulder this curtailment risk. In our view, this could be through a standalone voluntary congestion relief market, which we have discussed in our previous submissions.

1.2 Priority access can undermine the objective of investment efficiency

With time-based priority access (i.e. options 1 and 2 proposed in the consultation paper), there is a risk that market participants rush inefficient connections to 'bookmark' favourable queue positions. This can lead to suboptimal locations which limit renewable energy potential or require expensive upgrades given grid limitations.

Further, deficiencies in the other priority access options introduces:

- significant uncertainty to developers by departing away from a market-based approach (option 3)

- limited predictability from a dynamic grouping approach (option 4) making long-term project planning and financing difficult for developers.

Both can hinder new investment or raise investment costs via added premiums to account for this risk. In the case of the CIS, this is likely to see higher project bids and more expensive investment.

2. Hybrid model increases investor risks and fails its stated objective

[6] CIS Tender Brief. https://aemoservices.com.au/-/media/services/files/cis/cis-gen-nem/nem-tender-1-market-briefing.pdf?la=en.

Objective 2: Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.

This objective seeks to balance 3 competing aims: managing investor risk, promoting new entry, and ensuring a level playing field between existing players and new entrants to address cannibalisation risk.

2.1. Significant risks in the financial market will unlikely promote new entry

The hybrid model raises hedging concerns and introduces basis risk as the price generators receive for electricity (congestion relief market price) might differ from the price retailers pay (regional reference price). This mismatch makes it difficult for generators to sell hedge contracts to retailers in the financial market. Contract liquidity is a reported issue in the financial market likely to persist as old thermal generators, large sellers of hedge contracts, exit the market and are replaced by intermittent generation.[7] The impact of the hybrid model risks exacerbating this problem.

Under the hybrid model with the Congestion Relief Market (CRM), generators essentially must choose between potentially lower revenue but offering more attractive hedge contracts to retailers (by not participating in CRM), or more reliable dispatch but potentially lower revenue and less attractive hedge contracts (by participating in CRM).

- Not participating in CRM – generators can receive the regional reference price (RRP) for their electricity and offer contracts based on the full RRP to remain attractive to retailers. However the priority access framework might prioritise other generators to be dispatched more often meaning non-participating generators face 'volume risk'. This means less frequent dispatch translating to lower overall electricity production, fewer opportunities to sell electricity and fulfill contracts, and fewer hedge contracts they can offer retailers.

- Participating in CRM – generators are likely to be dispatched when available, reducing 'volume risk', but the CRM price might not guarantee generators the full RRP for all their electricity. These generators face 'price risk' as lower congested prices can translate to lower overall revenue if the CRM price is materially lower than the RRP. This makes offering hedge contracts based on the full RRP difficult

7 See Inquiry into the National Electricity Market: December 2023 Report (accc.gov.au), p94. See Enhanced wholesale market monitoring guideline (2024) | Australian Energy Regulator (AER).

as generators cannot guarantee receiving it themselves. As above this may lead to offering fewer hedge contracts overall.

Lower contract liquidity will not be sufficient to support ongoing retail hedging or incentivise new retailer entry – particularly those that are smaller and not vertically integrated – as an inability to access hedge contracts from generators raises significant risks. Downstream impacts will see hedging costs increase and higher prices for consumers,[8] which is counter to the long-term interests of consumers.

2.2 Considerable risks to existing and new PPAs will likely raise investment costs

Our previous submission to the Energy Security Board highlighted concerns about the increased complexity and regulatory risks associated with the priority access framework. These concerns remain unaddressed with the AEMC's hybrid model approach, particularly with the interaction of the CRM and its influence on the RRP as demonstrated by the AEMC's prototype testing.[9]

The complex pricing structure and uncertainty about future revenues in the hybrid model will create significant challenges for new and existing Power Purchase Agreements (PPAs) that provide predictable revenue streams for developers and price certainty for off takers. The CRM's impact on PPAs will depend on the type of agreement.

- The CRM's influence on RRPs might have a lesser impact on fixed PPAs which have a fixed pre-determined price for electricity throughout the contract term. However, significant and unexpected deviations from the anticipated RRP could still trigger disputes or require renegotiations, especially if the PPA includes provisions for adjustments based on market performance.

- Indexed PPAs, which link the electricity price to the prevailing RRP, would be directly impacted by the CRM's influence on RRPs, making these contracts more challenging to price upfront. Although we acknowledge that over time as these PPAs roll off, the impact will be lessened but not entirely removed.

To mitigate these risks, developers might factor in a risk premium when negotiating PPA prices, leading to higher electricity costs for large industrial consumers who purchase

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8 Retailer wholesale costs contribute around 33% of a residential customer bill and around 37% of a small business customer bill. An increase in wholesale hedging costs will raise consumer bills (if other cost components remain the same) Inquiry into the National Electricity Market: December 2023 Report (accc.gov.au), p 29.

9 AEMC, Transmission access reform, Consultation paper, 24 April 2024.

power through PPAs. Additionally, the hybrid model risks re-opening existing PPA contracts that are triggered when there are 'material changes in costs,'. Contract re-openers disrupt project financing stability, increase operating costs, and can discourage future investment due to the potential for uncertainty in revenue streams. Most of EA's existing PPAs would require changes if TAR was to proceed.

Further, the uncertainties introduced by the hybrid model make it challenging to effectively price and utilise hedge contracts for managing residual risk within PPAs. Hedge contracts rely on some level of predictability in the underlying market, which can be challenging with the complexities of the hybrid model.

2.3. Priority access does not address the root cause of cannibalisation

While priority access may offer some protection against cannibalisation it does not address the root cause - insufficient network capacity. In our view, each priority access option has deficiencies:

- Option 1 'Grouping by Time Window': does not fully prevent cannibalisation for geographically distant generators with different connection times.

- Option 2 'Grouping by Time-Window REZ Model': does not address cannibalisation between neighbouring REZs. Also disincentivises efficient non-REZ investment due to potential cannibalisation by REZ (contrary to promoting new entry in Objective 1).

- Option 3 'Two Tiers Approach': discourages non-REZ investment outside designated areas (contrary to promoting new entry in Objective 1). Also significant departure from market-based queue model.

- Option 4 'Dynamic Grouping Algorithm': highly complex and problematic as untested. Also likely difficult to build into a generator bidding strategy and would increase costs markedly as a result.

3. Non-cost reflective bidding can still occur in the hybrid model

> *Objective 3: Operational efficiency: Remove incentives for non-cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.*

This objective focuses on improving how electricity is delivered within the existing grid in real-time to achieve lower costs for consumers.

The two-stage dispatch CRM model seeks to address non-cost reflective bidding as generators who choose to participate in the CRM have physical dispatch bids that directly influence the physical RRP intended to incentivise more accurate bids that reflect their true costs. There are potential impacts however that undermine objective 3, which the AEMC have recognised in their paper. [10] These include:

- Perverse bidding: where non-opt in generators that are not exposed to the physical RRP can bid illogically in the access dispatch to affect the access of competitors or other generators in their portfolio. This could lead to inefficient grid congestion management.

- Contract market and settlement issues complexities, as described above – which translate to higher prices for consumers.

Further, prioritising certain generators through access dispatch could lead to higher overall system costs if it does not effectively address congestion. This is because non-cost reflective bidding can still occur, even with prioritized generators, if they are not the most efficient option for managing congestion in a particular situation. This outcome is contrary to the stated objective.

4. Hybrid model falls short of promoting consumer and two-way technologies

Objective 4: Incentivise congestion relief: Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.

This objective focuses on encouraging both consumers and two-way technology providers to play a role in reducing congestion on the grid.

The hybrid model with priority access and the CRM focuses on generation rather than demand. While the hybrid model may incentivise some generators to locate strategically (in a REZ or close to congested areas), it does not directly address demand side or two-way technology participation.

10 AEMC, Transmission access reform, Consultation paper, 24 April 2024.

Further, the two stage-dispatch which uses the access dispatch price dampens the price signal for demand-side resources to adjust their behaviour or for two-way technologies to participate effectively.

In our view, none of the priority access options or CRM models in the consultation paper appear to effectively address this stated objective. It is worth leveraging any existing policies regarding demand response programs and market mechanisms for aggregators to achieve this objective, rather than seeking to develop the hybrid model further.

5. The co-optimised model has severe deficiencies and introduces too much risk

While there may be some theoretical appeal in the co-optimised model to avoid the pitfalls of the two-stage dispatch model, it represents a major shift from the proposals considered by the Energy Security Board.

We do not support the co-optimised model as it introduces too much complexity and risk:

- CRM bids can influence and set the RRP and under co-optimisation, congestion prices are no longer distinct from energy prices, so participants are forced into mandatory participation to protect revenue generation. This creates uncertainty around future market conditions, long term contracts and revenue guarantees.

- Co-optimisation increases bidding complexity. Generators will have to submit "net bids" specifying the price they pay/receive for increasing/decreasing their output compared to the access dispatch quantity (buying/selling congestion relief). This differs from the "gross bids" used in the current system and two-stage CRM. This issue appears unaddressed by the AEMC.

- Co-optimisation raises settlement residue risk. The lack of a regional energy balance constraint in access dispatch raises concerns about potential settlement shortfalls (mismatches between payments and receipts) that may be difficult for transmission network service providers (TNSPs) to manage – ultimately passed on to customers. The AEMC acknowledges further investigation would be needed.

- Co-optimisation will require significant changes to NEMDE (the National Electricity Market Dispatch Engine) and associated systems, incurring significant development and testing costs. Without a cost benefit analysis, it’s unclear how the AEMC could consider that co-optimisation would producer higher benefits.

The AEMC acknowledge the concerns of co-optimisation raised by AEMO related to the RRP, funding shortfall, bidding combinations, and testing to date.[11] These concerns are significant.

There are many issues that still need to be worked through with co-optimisation, as acknowledged by the AEMC. Given the complexity and immense risk of this untested option we do not consider the co-optimisation model as a standalone option addresses the stated objectives and should not be progressed further.

We consider future resources and efforts are best directed elsewhere instead of progressing this further. We provide alternative pathways below.

6. Deficiencies in the cost-benefit analysis that should not be overlooked

There are deficiencies in the cost-benefit analysis set out in the consultation paper. The crux of the benefits appears to lie in improved investment decisions. However, industry itself expresses reservation about the proposed reforms. We also observe the sensitivity of figures in changes to the load weighted price which can materially reduce the reported net benefit.

The 'do nothing' scenario under the cost-benefit analysis, which serves as baseline for comparison is considered flawed. It assumes the current system remains unchanged for the entire period (2024 to 2025), which is unrealistic. Further, the interaction with existing policies such as the CIS and REZ is untested. Policies such as these that operate within the existing framework seek to improve the efficiency of the system, as discussed above, and the 'do nothing scenario' does not account for these. If the baseline scenario is unrealistic or underestimates future challenges, even minor improvements introduced by reforms will appear more beneficial in comparison.

It is widely acknowledged that the cost benefit analysis in the AEMC consultation paper is outdated, does not reflect the revised proposals and options in the hybrid model or fully considers the impact on the financial markets and PPAs. We have strong concerns with the validity of the results that justify progressing TAR and the hybrid model without correcting these issues. Accordingly, we have doubts that the benefits of fundamentally redesigning the market with the hybrid model would outweigh the cost given the issues and impacts discussed above.

[11] AEMC TWG workshop, 29 May 2024.

7. Significant risks with progressing the hybrid model further

Work to progress transmission access reform and the hybrid model, with a view to implement the reform can mean:

- **Delayed integration of renewables risk reaching climate targets.** As illustrated in figure 1 below, the current rate of projects reaching 'committed status' is already slow. We expect that the CIS announcement in December 2022 was likely a contributing factor with the market awaiting further detail on the policy. However, progressing TAR with a view to implement is likely to similarly risk delaying integration of new renewables and the energy transition. This would have ramifications on meeting state and federal climate targets and the national 2030 renewable energy target. While these targets may not be a stated objective under the consultation paper, they present a significant risk, and its impact must feature in the revised National Electricity Objective.

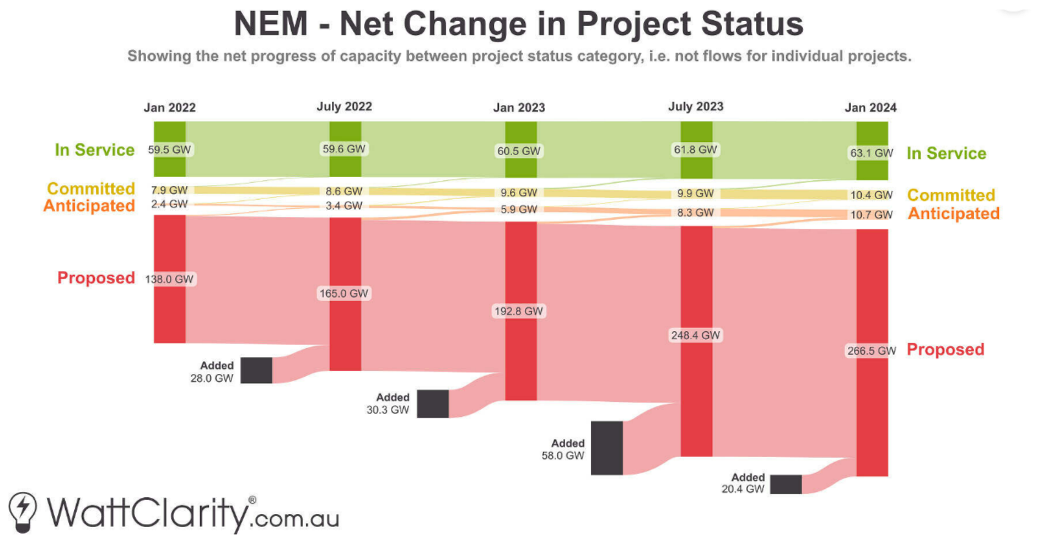
- **Higher costs for renewable energy investment**. Premiums on CIS bids are likely to increase to account for the risk and uncertainty expected to be introduced by the hybrid model. Higher CIS bids will see more expensive renewable energy investment, ultimately borne by taxpayers.

- **Higher electricity prices for consumers.** The complexities of the expected hybrid model, including challenges with new and existing PPAs, could lead to higher premiums to account for risk. This would translate to more expensive electricity for end consumers.

- **Stranded Assets and Wasted Investment:** Uncertainty around future market conditions and potential renegotiations of existing PPAs due to the expected hybrid model's complexities could discourage investment in existing generation infrastructure upgrades. This could lead to stranded assets and wasted investment in the long run.

The priority access options, two-stage dispatch and co-optimised CRM models have notable deficiencies, as discussed above. Accordingly, we do not consider these good standalone options against the stated objectives and should not be progressed further.

Figure 1



The net change between projects proposed and in service across the NEM between January 2022 to January 2024.

Source: AEMO Generation Information

8. Alternative pathways forward

Rather than progress the hybrid model further which raises risks, we consider future resources and efforts are best directed towards other pressing regulatory issues. However, if the AEMC wishes to present a pathway forward on TAR to Energy Ministers, we suggest the following narrowed options:

- Leverage existing policies like CIS and REZ and defer complex TAR reforms until the post-2030 review has completed.
    - We note that CIS agreements will be subject to a limited protection change-in-law provision, which only applies to new unforeseen market reforms. Noting that TAR is a 'live' policy proposal, it would not be captured by this CILP and therefore expose CIS agreement holders to bid price risks which cannot be avoided.

    - Generally, piecemeal wholesale market interventions will almost certainly create unforeseen and by-design problems which cannot be resolved without acceptance of their real impacts. Instead, we believe that a more holistic approach through the Post 2030 review would be better and could be used to assess the effectiveness of CIS and REZ implementation to determine if inefficient new investment decisions in combination with race to the floor bidding continue to create the growing problems identified by TAR.

- Reconsider the voluntary standalone CRM model proposed by Edify Energy, which does not appear to introduce the complexities of the hybrid model but still reflects long run marginal costs in generator bids.
  - Congestion can lead to curtailment of incumbent renewable energy production, which is not compensated for in CIS agreements. As such generators with CIS agreements, irrespective of their location (although almost all are expected to be located within a REZ), will be exposed to congestion risk. As generators have limited control over congestion (once built) and cannot easily forecast it, we believe a voluntary physical CRM could incentivise congestion relief without the challenges of the priority access options, or two stage-dispatch in the hybrid model.

- Exploring a dynamic (or periodically reviewable) NEM-wide controlled access policy, implemented through existing REZ programs.
  - This approach would leverage established frameworks by jurisdictional governments and implement a common set of rules to protect REZ regions from congestion and/or curtailment risks. The NEM access framework should either be dynamically applied by AEMO on a regular interval basis (to be determined) or subjected to a periodic review - acknowledging that some congestion/curtailment risk is healthy in the system.

In our view, the above pathways, either standalone or together, offer a less risky and more familiar path forward than fundamentally redesigning the market with the proposed hybrid model.