26 May 2023

Submitted via email to info@esb.org.au

Dear ESB

Transmission Access Reform Consultation Paper – May 2023

Hydro Tasmania welcomes the opportunity to respond to the ESB's *Transmission Access Reform Consultation Paper.*

Hydro Tasmania has been actively involved in access reform discussions, including participation in working groups and industry forums, and comprehensive submissions to various consultation processes. To assist in quantifying the scale of the congestion challenge facing our industry, Hydro Tasmania developed a methodology for estimating the actual amount and cost of thermal curtailment resulting from increased VRE deployment. This analysis indicated that while thermal curtailment in our grid is currently relatively immaterial in 2022, it has been notably increasing in recent years.

Recognising this upward trend and the materiality of congestion risk facing our power system, Hydro Tasmania's response to the Energy Security Board's (ESB) Directions Paper (November 2022) provided conditional support for the progression of a congestion relief market (CRM) paired with priority access. This support was contingent upon several factors, including:

1. **The presentation of robust modelling** that both evidences the value of this reform and demonstrates its capacity to work cohesively under current and future market frameworks.
2. **The resolution of key design choices which have significant implications for market participants.**
3. **Ensuring that inter-regional trade is not disadvantaged under any new market and/or access scheme**.

Hydro Tasmania commends the ESB on significant progress made developing the hybrid model, however several of the above points remain unaddressed. As such, **we support ongoing development of the hybrid model but do not consider that it is sufficiently progressed to proceed to rules drafting.**

Absent a truly finalised design, and a fully-fledged and readily available prototype of the hybrid model, it is highly difficult for industry participants to understand the benefits and risks associated with the reform. Similarly, a lack of design details will likely make it difficult for Federal and State Governments to understand how the proposed reforms while be complementary to (or at least not hinder) the realisation of their own policy ambitions.

On this basis, we believe **the most pragmatic approach will be for the ESB to present Energy Ministers with progress on the reforms to date, but recommend further time to develop the model**, before agreeing to proceed to rules drafting. Hydro Tasmania's comments on the unresolved CRM and priority access design details are addressed in **Attachment 1** to this submission.

We look forward to ongoing engagement with the ESB as this design process progresses. If you wish to discuss any aspect of this submission, please contact Jonathan Myrtle (Jonathan.Myrtle@hydro.com.au).

Yours sincerely,

John Cooper
Manager Market Regulation

Attachment 1 – Hydro Tasmania's comments on unresolved design details

i. PRIORITY ACCESS MODEL OPTIONS

1a. Do you prefer the queue option or the centrally determined tiers option?

Hydro Tasmania is strongly supportive of the ESB working towards a relatively granular number of queue positions, as opposed to an overly conservative tiered approach.

Hydro Tasmania believes that a centrally determined tier approach could introduce unnecessary risk and complexity to the scheme's design. We consider this will likely prove a cumbersome process, and may not easily adjust to changing market dynamics (i.e. changing line ratings etc.) On this basis, we believe the preferable approach would be for participants to reach their own conclusions on the inherent risk of congestion under a queue model. This self-assessment would be strongly facilitated and supported by leveraging improvements made under the Enhanced Information Provision work.

Notwithstanding, we recognise the challenges associated with a higher number of queue positions stated throughout the consultation paper, including the risk of additional computational complexity for NEMDE. As expressed in our response to the ESB's Directions Paper (Nov 2022), we also recognise the risk that *'…an approach that is very granular may shift the 'winner takes all' outcome of today's dispatch (based on coefficients) to a 'winner takes all' outcome based on when a generator achieves connection.'* It will be important that any queue position approach also adequately balances the need to facilitate an improved efficiency of dispatch. This balance will be best achieved through some efficient mix of queue numbers/dispatch priority paired with ongoing consideration of each impacted generator's constraint coefficient (i.e. hard vs soft priority). This is explored further below.

1b. At what point in the connection process should queue numbers or tiers be assigned?

Early indications of queue numbers or tiers will be essential. Absent this insight, it is reasonable to assume that new projects will be unable to reasonably build in their curtailment risk to their business case developments. In providing this insight, further transparency on other projects seeking connection in their 'zone' will also be relevant.

2a. Do you favour queue numbers being assigned in strict chronological order or in time-windows?

In order to address concerns regarding new entrants "rushing in", we consider that time-windows will be a pragmatic approach. Nonetheless, we question the materiality of the risk of "rushing in", noting that all projects will continue to face a range of other hurdles through the development process. This can include management of project timelines and costs, establishing confidence in long-term views of pricing outcomes and contracting processes.

3a. Which sub-option do you prefer; first-come-first-serve or auction? Why?

In general, we support a first come first served approach to priority access. Auctions are likely to introduce an unnecessary layer of complexity and costs into an already complex reform. In addition, auctions under a priority access model would introduce many of the deficiencies of the congestion fee model into the preferable model.

The exception to this may be for REZs being developed by different jurisdictions. When there are prescribed limits on the amount of capacity entering a REZ, jurisdictions may seek to allocate this limited capacity through an auction process.

In considering first-come-first-served approaches, the ESB should also be giving close consideration to how redevelopment, refurbishment and expansion of existing assets are treated under the scheme.

3b. What is the preferred metric to delineate the tiers?

The ESB has proposed delineating tiers of access for generators by splitting NEM regions into sub-regions/zones. While this seems like a novel idea, it remains difficult to understand the efficacy of this approach without further understanding how this would be enacted (i.e. methodology to determine these sub-regions). Hydro Tasmania remains sceptical as to whether this will be a plausible approach, noting the meshed nature of our transmission network. Further work is required to develop this methodology and should logically draw insight from the ISP and other jurisdictional plans to augment and expand transmission networks.

We have formerly opposed the use of centralised modelling to determine the 'efficient hosting capacity' of our transmission network. Line-ratings will naturally fluctuate dependent on a variety of factors, and we believe this approach would fail to capture the dynamic nature of transmission capacity. Under certain ambient and system conditions, lines will be capable of facilitating much higher or lower shares than what may be indicated by a static assessment of 'efficient hosting capacity'. In turn, we believe this will create a risk of transmission assets being over or under-utilised. One way to manage or provide insight to this is to provide a base case of efficient hosting capacity, but also include weighted probabilities / estimates of line ratings under different operational conditions.

To avoid the 'winner takes all' concerns expressed by some market participants, we'd strongly encourage the design process to take into consideration what sorts of 'pain sharing' arrangements might be possible between Tier members – This could prove a useful guide or even alternate to the hard vs soft priority approach (i.e. relying on some mixture between constraint coefficients and queue positions).

3c. Should the tier delineations be set forever or redetermined periodically?

To reflect changing line capacity, redetermining tier delineations will be necessary. Redetermining these delineations should be conducted only as necessary. Similar to an iterative update to the ISP, we believe redetermination of tier delineations should only occur where a material change has occurred in line capacity. For instance, where a transmission component has been substantially derated, a generator retires, or a transmission augmentation project substantially increases the line's hosting capacity.

<u>ii. POLICY LEVERS</u>

1. Where on the hard versus soft spectrum should priority access be?

We agree with ESB that it is difficult determine the appropriate balance between addressing the current problem of cannibalisation of access versus maintaining a signal for generators to efficiently use transmission capacity through their location decision. We also note that priority can be conferred on a soft to hard spectrum and this will result in some trade-off between these two competing effects.

Hydro Tasmania's submission on the transmission access reform directions paper identified that the amount and cost of curtailment has grown substantially in recent years. The AEMO's 2022 Integrated System Plan also forecasts VRE curtailment growing significantly out to 2050. We consider that the cannibalisation of access and congestion risk are immediate issues imposing significant costs on consumers today.

We agree that in principle, hard priority could create a new problem where generators locate in areas of the grid which use spare transmission capacity inefficiently. Hard priority may also have similar effects as having very granular number of queues which we noted in response to the ESB's Directions Paper (Nov 2022), "*may shift the 'winner takes all' outcome of today's dispatch (based on coefficients) to a 'winner takes all' outcome based on when a generator achieves connection.*' However, the magnitude of these effects and impact are unknown. We recommend continued testing of the impact of different hardness and softness settings in AEMO's hybrid prototype, with results presented to industry to inform the discussion.

2. What is the preferred basis for the length of priority access?

We agree that the firmness and duration of priority access has many of the same trade-offs as the degree of priority design choice. For the same reasons in our response to 2(a), we suggest ESB to put more weight on addressing the original problem of cannibalisation and congestion risk.

In our directions paper, we recommended that *"new and existing generators could be provided a queue position for 90% of their capacity but have 10% of their capacity at the back end of the queue (exposing it to some congestion risk). This would maintain the increased certainty around access, avoids sudden and inefficient changes in the newly created congestion signal, and could be calibrated such that no project is fully insulated from congestion risk."*

We consider that this approach appropriately balances between addressing the original problem versus addressing the potential problems of generators using transmission capacity inefficiently or delaying efficient divestment. As with our response to 2(a), we encourage ESB to monitor the behaviour of new and existing generators to determine how significant those potential problems become.

<u>iii. LEGACY GENERATORS</u>

1. How should legacy generators be assigned priority access?

We acknowledge that designing an appropriate approach to the treatment of legacy generators is difficult and note that ESB has presented three options with a summary of their strengths and weaknesses. Across the options, there is a trade-off between limiting windfall gains/losses to legacy generators versus limiting regulatory risk.

Hydro Tasmania agrees with ESB that a fundamental principle in public policy to limit regulatory risk is that *"regulatory changes do not substantially impact on the value of sunk investments"*. We consider that adhering to this principle is a high priority because:

- Negative perceptions about regulatory risk are long-lasting and difficult to reverse.

- Investors have limited options for managing regulatory risk – negative sentiments about the regulatory environment will be reflected in a higher cost of capital and/or reduced investment appetite which will hinder the NEM's transition.

Hydro Tasmania agrees that an approach which results in windfall gains/losses to legacy generators could lead to an inefficient investment rush or strike. However, any such efficiencies are limited in scope – that is, it is a once-off source of inefficiency and will not persist into the future – and we consider that there are viable options to minimise this inefficiency.

With these points in mind, we recommend the ESB adopt the **highest priority level for the full asset life** option for the treatment of legacy generators. The table below provides our assessment of each option in detail:

Options for the treatment of legacy generators

Options	ESB assessment	HT's overall assessment
Highest priority for the full asset life	**Pros** • Simple • Limits regulatory risk and so promotes future investments **Cons** • Likely to result in a windfall gain to legacy generators, resulting in a rush for inefficient investments	**HT supports this option.** We agree that this option is simple to implement and limits regulatory risk. We consider that there may be a windfall gain to some legacy generators and a rush for inefficient investment. However, this inefficiency is a once-off and will not be an ongoing source of inefficiency. We recommend ESB to consider options for minimising this inefficiency including conducting more thorough evaluations of connections or setting the demarcation date for defining legacy generators at the same time as when details of the reform have been finalised.
Initial assignment to the highest priority with a glide path	**Pros** • Seeking to replicate that legacy generator access can fall over time in the status quo arrangements **Cons** • By demoting legacy generators through the queue/tiers, the access of new generators is promoted even in parts of the grid that are already congested – potentially incentivising inefficient investment • Complicated to calibrate to replicate status quo. If	**HT does not support this option.** While the pro identified by ESB for this option is attractive in principle, we consider that replicating the outcome under the status quo for each generator is unlikely to be achievable in practice. The current arrangements affect different legacy generators differently e.g. legacy generators with low coefficients are less affected by current or future congestion. If the reform applies a single glide path arrangement (representing an

	unsuccessful, may create a rush or investment strike, and increase regulatory risk	average level of access degradation) to all generators, then legacy generators with low coefficients will experience a windfall loss relative to the status quo. On the other hand, we do not consider determining an individual glide path for each generator to be realistic. We agree with both the cons identified by ESB and in particular, note that this option increases regulatory risk.
Split a legacy generator's capacity across priority level	**Pros** • Simple and transparent, once initially set up **Cons** • By reserving high priority access for newcomers, entry is incentivised even in parts of the grid that are already congested – potentially incentivising inefficient investment • Complicated to calibrate to replicate the status quo. If unsuccessful, may create a rush or investment strike, and increase regulatory risk.	**HT does not support this option.** We consider that this option could be difficult to administer. For example, determining the appropriate split of a legacy generator's capacity across different tiers/queue positions will require stakeholder consultation. We agree with both the cons identified by ESB. This is our least preferred option as the cons (particularly the increase in regulatory risk) are significant and we also anticipate that this option will come with major administrative burden.

Our internal analysis reaffirms NERA's finding that any windfall gains/losses from implementing priority access is more likely to affect legacy renewable generators rather than fossil fuel generators. We find that existing wind and solar farms will be the biggest beneficiaries of grandfathering because:

- The correlation of wind and solar resources, together with the projected growth in their capacity means that these generators are currently at greatest risk of cannibalisation
- Market prices tend to be low during periods of high congestion/curtailment meaning that energy limited dispatchable/thermal assets will be seeking to run at low levels.

2. How should legacy generators be defined i.e. how should the demarcation date be set?

Our view is that setting the demarcation date quite late, such as after the full implementation of reform, would increase the scope for prospective generators inefficiently rushing or delaying connection. In the lead up to a late demarcation date, future generators would have enough information about the reform to determine the potential windfall gains/losses and make connection decisions on that basis.
On the other hand, setting the demarcation date early, such as a point in time in the past, would disadvantage generators currently in the connection process. These generators would not have been

able to determine the impact to their access from reform and likely made connection decisions based on the assumption of the status quo arrangements continuing. We consider that treating these generators as legacy generators would be in line with the principle behind reducing regulatory risk.

We recommend ESB to apply the general principle to classify generators as a legacy generator if they are likely to have made connection decisions based on status quo arrangements. We propose that setting the demarcation date in line with the timing of Ministerial approval of final policy recommendations could be considered by ESB.

<u>CRM MODEL OPTIONS</u>

<u>iv. SETTLEMENT RESIDUE</u>

1. Do you have any feedback on the alternative approaches to allocate the CRM residue?

Allocation of new settlement residues arising from the CRM is a critical consideration for the new policy design. To date, the ESB has not provided sufficient data and analysis to substantiate the view outlined in the consultation paper that this newly created residue is unrelated to inter-regional flows. Absent such information, our preliminary view is that the newly created residues should be allocated to holders of settlement residue auction units on the basis that it would assist with unit firmness and help facilitate inter-regional trade and risk management. To this end, we support the points made in the Australian Energy Council's submission on this matter.

<u>v. CRM BIDDING STRUCTURES</u>

1. Do you agree with the proposed approach to modify the CRM bidding structure?

Hydro Tasmania's preliminary view is that some of the proposed approaches the modifying the CRM bidding structure are not required and may introduce unnecessary complexity in scheme design. We do not consider that a bidding structure based on the energy market (10 prices and volume bands) would deter participation in the CRM; rather participants are familiar with current bidding arrangements and would evolve their strategies achieve their targeted outcomes in the CRM.

<u>vi. FCAS BIDS AND PARTICIPATION</u>

1. Do you have any comments on the proposed approach for FCAS bids and participation in the CRM design?

We agree that introducing two sets of FCAS bids (that is, bidding in another 10 markets in the CRM) is likely to impose additional costs for participants with immaterial efficiency gains. For this reason, absent any clear evidence of efficiency implications, we support the ESB's preliminary preference to use only one set of FCAS bids in CRM design and the proposed FCAS settlement formula.