21 December 2022

Submitted via email to info@esb.org.au

Dear ESB,

ESB Transmission Access Reform Directions Paper (November 2022)

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

Transmission access reform has been a key topic in the regulatory reform agenda of the National Electricity Market (NEM) for several years. Recognising the emergence of congestion challenges facing our market, Hydro Tasmania has been actively involved in access reform discussions. Our engagement has included: providing comprehensive submissions to consultation processes; participation in industry forums and technical working groups; and the development of our *Synchronous Services Market* rule change proposal.

Hydro Tasmania commends the ESB on its collaborative approach and progress to date developing its hybrid model. While we broadly agree with the ESB's rationale for pursuing these reforms, we note that the ESB has not released specific modelling and analysis of the current and future costs of congestion which was scheduled for release in October 2022, nor any modelling to quantify the costs of implementation. Thorough scrutiny of this analysis is essential for market participants to understand and agree the materiality of thermal congestion facing the sector, and to ensure these reforms will result in a net benefit for consumers.

As part of our ongoing constructive engagement in transmission reform, **we have developed a methodology for estimating the actual amount and cost of thermal curtailment** resulting from the increased deployment of variable renewable energy (VRE) in the NEM. **Appendix 4** of this submission outlines our methodology and provides a comprehensive assessment of the level of the thermal curtailment evident in the grid today. This analysis shows that in 2022, thermal curtailment remains relatively immaterial, however has grown substantially compared to previous years. This analysis provides a high-level sense check of the materiality and overall trends relating to congestion in the NEM in advance of additional material to be released by the ESB.

Based upon the information presented in the consultation paper, Hydro Tasmania has assessed both hybrid variant models against the reform assessment criteria (**Appendix 1**), and **conditionally supports the progression of a Congestion Relief Market paired with Priority Access**.

Advantages of Priority Access over Congestion Fees

We believe that Priority Access is the far superior investment timeframe model due to it:

- Appropriately **reflecting the dynamic nature of grid capacity** and largely avoiding the application of 'static' assessments to determine generator access.
- Providing **greater certainty to existing and new entrant generators regarding their level of access** moving forward. Conversely, the congestion fees approach would disincentivise but not preclude new generators from creating congestion.
- Ensuring that the **congestion costs are more appropriately allocated between market participants**, with better targeting of those parties causing congestion, while still facilitating marked improvements in the efficiency of final dispatch through the CRM.

We have significant concerns around the workability of the congestion fees model. The development of a congestion fees approach is likely to be a very complex undertaking, given the need to adequately and accurately model, assess and allocate congestion cost on to a new entrant. There is a high risk that this congestion fee would evolve into an administratively cumbersome process which could slow new investments and connections and in turn, increase costs for consumers.

Hydro Tasmania's <u>full support</u> of the CRM/Priority Access model is <u>contingent upon</u>:

- **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.
- **The resolution of key design choices which have significant implications for market participants,** such as:
  - The **duration of priority access rights** allocated to generators, **including appropriate grandfathering provisions** for existing generators;
  - The drafting of **bidding rules and guidelines** to carefully regulate participation between energy and CRM markets; and
  - Careful and measured consideration of **potential impacts on current and future market contracting and spot price impacts**, particularly with regard to any new approaches to setting the regional reference price.
- **Confidence that the critical and foundational market reform principle of technology-neutrality is upheld**, such that storage and investments with long asset lives are not unduly disadvantaged by this proposed reform.
- **Ensuring that inter-regional trade is not disadvantaged under any new market and/or access scheme**. The ESB should carefully assess the impact of the proposed reforms to ensure they will not undermine or negatively impact investments made in current and future interconnection assets.

Other matters

We note that the ESB intend to revert to the Congestion Management Model (CMM) in the event that modelling indicates that the CRM will be too costly to implement. The CMM is not well supported by industry, nor has it been thoroughly considered at this stage of the consultation process. Reverting to the CMM would severely limit any meaningful period of consultation that must be afforded to stakeholders, prior to providing final recommendations to Ministers. Should the CRM fail the cost benefit assessment, the ESB should extend the consultation period to allow a more robust assessment of the CMM, and interactions with the investment timeframe models.

Hydro Tasmania encourages the ESB to assess whether the proposed CRM may benefit from a broader application to improve market outcomes under other constraint types, in addition to relieving thermal congestion. It may also be appropriate to assess the inter-related nature of these proposed reforms with other reforms currently under consideration, such as the *Operational Security Mechanism.*

Hydro Tasmania has provided commentary on the **CRM model in Appendix 2**, and **the investment timeframe models in Appendix 3 of this submission**.

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

Appendix 1 – Hydro Tasmania assessment of hybrid models against ESB's reform objectives

Key

● *Fully achieves the transmission access objective*

◐ *Partially achieves the transmission access objective*

○ *Assessment outcome is pending outcomes of detailed design choices and ongoing consultation with the market bodies*

Table 1 Summary of access reform assessment criteria for the Hybrid model with Congestion Fees

Access reform assessment criteria	ESB rating	HT rating	HT comments
Efficient market outcomes – investment	●	◐	We have concerns about whether designing a methodology for calculating a congestion fee which is transparent, repeatable, timely and provides accurate locational signals for investment is a realistic goal. We consider that major trade-offs will be required on at least some (if not all) of these requirements which will compromise the ability for this model to facilitate efficient locational investment decisions and lower the cost of capital for new investments (a barrier to entry for new assets).
Efficient market – dispatch	●	●	We agree that the CRM will facilitate more efficient dispatch in operational timeframes.
Appropriate allocation of risk	◐	◐	We agree that this hybrid variant would only partially achieve the 'Appropriate allocation of risk' objective. The congestion fees approach would disincentivise but not preclude new generators from creating congestion and creates an administratively cumbersome process which could act to slow new investment and connection. We also note that the effectiveness of this approach is highly dependent on the calculation of the fee – and that this fee is determined by a party which is not financially impacted by the outcome of this assessment (that is, not exposed to a financial risk from setting the fee with poor accuracy).
Manage access risk	◐	◐	We agree that this hybrid variant only partially achieves the 'Manage access risk' objective. To the extent that trade-offs are made between the desired features of the methodology for calculating the congestion fee, this hybrid variant may not adequately reduce the risk to investors. For example, a methodology which trades off accuracy for simplicity could lead to existing generators bearing more access risk than the efficient level if the congestion fee under-prices the congestion cost of new entrants.
Effective wholesale competition	●	◐	If the methodology for calculating congestion fees is not sufficiently transparent, timely or repeatable or over-prices the congestion cost of new entrants, then this hybrid variant will present a barrier to new entrants.
Implementation risk	◐	○	We consider it too early to give the 'Implementation risk' criteria a rating of 'partially achieves the transmission access objective' without further analysis and consultation. As discussed in Section 5.4 of the Directions Paper, there are significant design choices relating to the methodology and process for calculating the fee which still need to be resolved. The major delay in delivering modelling as part of this consultation process highlights the challenges and risks associated with using a centralised modelling process to accurately determine congestion fees.
Integration with jurisdictional REZ schemes	●	●	We agree that this hybrid variant allows for integration with jurisdictional REZ schemes.

Table 2 Summary of access reform assessment criteria for the Hybrid model with Priority Access

Access reform assessment criteria	ESB rating	HT rating	HT comments
Efficient market outcomes – investment	●	●	We agree with the ESB's assessment.
Efficient market – dispatch	●	●	We agree that the CRM will lead to more efficient dispatch in operational timeframes.
Appropriate allocation of risk	●	●	A queue mechanism provides greater certainty to existing and new entrant generators regarding their level of access moving forward. It also ensures that the congestion costs are more appropriately allocated between market participants, with better targeting of those parties causing congestion, while still facilitating marked improvements in the efficiency of final dispatch. The risk of congestion caused by new entrants will be more strongly borne by those new entrants under a queue mechanism.
Manage access risk	●	●	This hybrid variant appropriately reflects the dynamic nature of grid capacity and largely avoids the application of 'static' assessments to determine generator access. A queue mechanism also provides a transparent signal to existing generators and prospective new entrants about their level of access over the long term. We consider that this will give investors more certainty and lower the cost of capital. That is, new entrants with marginally more favourable coefficients will no longer be able to cannibalise the access of existing generators – despite not being more efficient. Rather, new entrants can only gain access through the CRM by being more efficient / lower cost than incumbents.
Effective wholesale competition	●	●	A queue mechanism maintains contract market liquidity by building upon and enhancing the current market design. We consider that this hybrid variant will also not hinder efficient new entry even to areas with congestion. Efficient new entrants can access the RRP during non-congested periods and generate revenues at their LMP through the CRM during congested periods. In this way, this hybrid variant facilitates effective wholesale competition whereby new generators will enter congested areas only where efficient to do so.
Implementation risk	○	○	We agree that there will be implementation challenges and support further analysis and consultation.
Integration with jurisdictional REZ schemes	●	●	We agree that this hybrid variant allows for integration with jurisdictional REZ schemes.

Appendix 2 – Hydro Tasmania's comments on the CRM model

The Congestion Relief Market (CRM) model is the product of significant stakeholder engagement and collaboration across industry. Through iterative refinements to the original Edify Energy proposal, we believe we are now presented with a preferable option to manage emerging congestion in the NEM, compared with the potentially disruptive Congestion Management Model (CMM). The below sections state Hydro Tasmania's views on key design considerations for the CRM.

Implementation considerations

- **Hydro Tasmania does not support a staged implementation of the CRM and Priority Access.** We believe that a staggered approach risks unnecessarily complicating the implementation process. This is likely to create transitionary burden for generators. Instead, it would be more appropriate to implement both the CRM and investment timeframe models concurrently.

  Critical to a smooth transitionary period will be to ensure that market participants are afforded sufficient lead-time to familiarise themselves with the new operating regime, and opportunities to make any amendments necessary to contracts that may be impacted. To support a smooth transition, Hydro Tasmania strongly encourages the ESB to consider targeted education initiatives and worked examples/models to demonstrate how bidding practices will change. Given the complexity and scale of the change, we also encourage ESB to ensure end-to-end offline system testing is conducted as part of the implementation process.

- **Any modelling conducted to justify the benefit of proposed access reforms must consider the full suite of State and Federal policies aimed at expanding and modernising the transmission network**. These policies currently include: The Federal Government's *Rewiring the Nation* program; Queensland's *'Supergrid'*; Tasmania's *North-West Transmission Development Plan*; Victorian and New South Wales *Renewables Energy Zones*; and so on. These projects will collectively have a substantial bearing on the hosting capacity of the network. It is reasonable to assume that investors will continue to prioritise projects that capitalise on the above policies. It is important that modelling does not overstate the value of the proposed transmission access reform by failing to recognise the increasing hosting capacity.

Coefficient rounding

Questions for stakeholders

The ESB has proposed a decision option to round constraint coefficients in the energy market.

Q4. Do you agree with the assessment of risks and opportunities for these design options?
Q5. What is your preferred option and why?

Q4. Yes.

Q5. Hydro Tasmania cautiously supports the idea of rounding coefficients to reduce the impact of the 'winner takes all' aspect of energy market dispatch and the associated wealth transfers that may occur. Care must be taken in determining an appropriate level of rounding: rounding to 1 decimal point may represent too large a change and begin to introduce material inefficiencies in dispatch; rounding to 2 decimal points may not represent a sufficient change from the status quo.

We have developed a real-world example to demonstrate how small differences in coefficients can have a significant impact on dispatch outcomes. In Table 3 below, we show the % of output curtailed in 2022 (calculated using our methodology discussed in Appendix 4) and the coefficient for three generators in the **V>>V_NIL_18** constraint – the most common thermal constraint in Victoria. The results suggest that the % curtailed due to thermal constraints is very sensitive to the size of its coefficient in the **V>>V_NIL_18** constraint. The percentage curtailed at Ararat Wind Farm is almost 10 times more than Bulgana Green Power Hub despite their coefficients differing by only 0.0363.

Table 3 Percentage of availability curtailed vs coefficient in 2022 (to December)

Generator	% output thermally curtailed	Coefficient in V>>V_NIL_18
Ararat Wind Farm (ARWF1)	6.8%	1.0000
Crowlands Wind Farm (CROWLWF1)	2.1%	0.9874
Bulgana Green Power Hub (BULGANA1)	0.7%	0.9637

Managing inter-regional transfers

The Directions Paper provides some high-level commentary on the potential impacts of a CRM on interconnector flows, such as the potential for clamping, and the opportunity to refine settlement residue auctions (SRA)/inter-regional settlement residues (IRSR) processes. Hydro Tasmania strongly encourages the ESB to conduct further analysis to understand the potential physical implications of a CRM on inter-regional transfers as well as impacts on settlement residues in the energy market (particularly when paired with a priority access model).

- We would encourage the ESB to specifically assess whether it may be prudent for interconnectors to be given their own 'queue' positions under a priority access model. Alternately, congestion fees should be calculated with reference to any constraints they may impose on energy delivered across interconnectors to access the neighbouring jurisdictions regional reference node.
- This analysis is important given that interconnectors are poised to play an increasingly important role in our power system as we move towards higher shares of VRE and rely heavily upon inter-regional transfers of energy to meet demand.

Dealing with multiple binding constraints

Hydro Tasmania is unclear as to how the proposed CRM model would work in a meshed network, where two or more generators are behind multiple and simultaneous binding thermal constraints. It would be greatly beneficial if the ESB could provide a worked example as to how the CRM would settle between these constraints.

It would be particularly helpful if this could be demonstrated using a 'real world' example, where two constraints are binding simultaneously, impacting multiple generators.

Bidding rules between energy market and CRM

Questions for stakeholders

The ESB has proposed options in response to the new arbitrage opportunities between the energy market and the CRM.

Q6. Do you agree with the analysis of key risks and opportunities for each design option?

Q7. Are the design choices more applicable to certain categories of market participant?

Q8. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?

Q6. Yes.

Q7. In general, the same design choice should be applied consistently across different market participant and technology categories.

Q8. We agree that that the new CRM market will change incentives for bidding into the energy market and, when out-of-merit generators/load bid below RRP, has the potential to create material and unpredictable transfers between market participants.

The ESB has presented three options to manage this potential design flaw. Hydro Tasmania considers that this potential 'loophole' in the CRM design should be addressed, and hence, Option 1: Keep existing energy market design is not appropriate. Hydro Tasmania prefers Option 2: Updated Bidding Guidelines, as such an approach would allow discretion of market participants, regarding their operating costs, portfolio optimisation implications and so on. Where perverse or unreasonable conduct is suspected, monitoring by the AER with a strong penalties framework may be sufficient to deter gaming between the markets. We also note that this would represent an extremely complex task for the AER and that the rules would need to be carefully developed such that clear breaches can be identified and penalised.

Hydro Tasmania strongly discourages pursuing Option 3: Automated measures to artificially cap bids in the CRM. The NEM is arguably one of the most dynamic markets in the world and assets are frequently changing their bid price and volumes in response to changing market conditions. For example, hydropower and storage assets price their supply based on the opportunity cost of supply rather than input costs.

Treatment of storage as generator and load

Questions for stakeholders

The ESB has proposed options for the treatment of storage as a generator and as load.

Q1. Do you agree with the underlying assumptions for the respective incentives of storage acting as a generator and as load?

Q2. Do you agree with the analysis of key risks and opportunities for each design option?

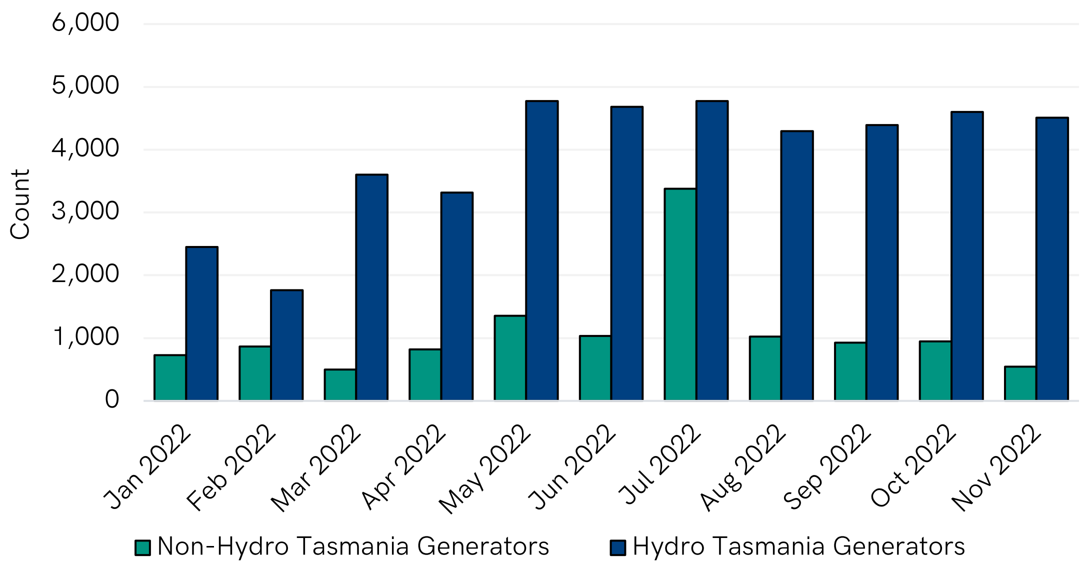
Q3. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?

Q1. Yes.

Q2. Hydro Tasmania cautions against the use of a 'strike price' to determine whether a storage asset is deemed in or out-of-merit in the dispatch process. This is an exceedingly blunt instrument which would fail to capture the fluctuating values of energy in storage for hydropower and other storage assets. As noted above, hydro and storage assets price their supply based on the opportunity cost of supply rather than input costs and will frequently change bid prices and volumes in response to changing market conditions. Any blurring of these market signals will likely disadvantage consumers in the long run.

For example, Hydro Tasmania averaged more than 3,900 price band changes per month in 2022 (Figure 1) in response to changing market and storage positions and this is more than all other generators in the NEM combined. Attempts to set an administered strike price is likely to limit hydro and storage generators' ability to operate efficiently in the market, likely leading to higher market prices in both operational and investment timeframes.

Figure 1 Monthly total price band changes across Hydro Tasmania's generators in 2022 (to November)



Notwithstanding, we appreciate the potential for inefficiencies to occur through strategic bidding, creating wealth transfers away from in-merit generators to storage assets that may not necessarily incur the costs of dispatch. These inefficiencies may be better addressed by placing energy limits on storage assets in the energy market, like today's dispatch. For example, a battery with 2 hours of storage could be limited to 4-6 hours of dispatch in the energy market assuming that it cycles 2-3 times per day.[1]

Q3. For uniformity and simplicity, we consider it may be most appropriate to apply the same rules to storages as all other generation assets. If necessary, the amended bidding guidelines, and monitoring practices of the AER could have specific reference to storage assets and outline how these assets should respond during periods of thermal constraint. Energy limits may also be appropriate, particularly for short-duration storage, and assist in preventing wealth transfers between in merit and out of merit generation.

[1] This is just a conceptual example and determining the actual amount would require rigorous analysis.

Calculation of the RRP

Questions for stakeholders

The ESB has outlined two options for the calculation of RRP which has consequential impacts for the treatment of FCAS in the CRM.

Q4. Do you have a preferred calculation for RRP and why?
Q5. Which approach do you prefer for the treatment of FCAS and why?
Q6. If the technical implementation plan requires that we adopt your non-preferred calculation of RRP and FCAS prices, what are the risks?

The calculation of the RRP represents a significant aspect of the CRM model and there are many complexities in the different design choices which must be carefully considered. The Directions Paper does not provide sufficient information and/or worked examples to understand the ESB's intent across different design options for the calculation of the RRP under the proposed CRM framework. Nor has the ESB released any detailed modelling and/or analysis on how the different RRP formulation would work in practice. On this basis, we are currently unable to determine a preferred option. We will continue to engage with the ESB in several forums, including its Technical Working Group, to better understand this issue and assist with the selection of the most appropriate approach.

Appendix 3 – Hydro Tasmania's comments on Investment timeframe models

Thermal congestion is currently at relatively low levels in the NEM (see Appendix 3), but as outlined in AEMO's 2022 ISP, congestion is expected to grow significantly over time. The ESB has proposed two potential models to better calibrate the congestion costs between new and existing assets: **priority access** and **congestion fees**.

Some market participants have expressed a view that existing assets should be subject to competitive market forces and not be protected from the price impact of new investments entering the market. While we understand the rationale for this position and the value of competitive tensions to drive efficient market outcomes, it is Hydro Tasmania's view that a failure to provide some enduring risk mitigation for existing generation assets would be in direct contradiction to the objectives of this reform. We consider the winner takes all nature of dispatch, the government-led development of REZs and the scale of the NEM's transformation makes this sector unique and warrants different treatment to other sectors.

Of the two models proposed, **Hydro Tasmania has a strong preference for the priority access model** for the following reasons:

- **Greater investment certainty** – the priority access model enables investors to determine the level of access for new assets based on conditions at the time of making their investment. Importantly, the priority access model will recognise and adapt to the physical and constantly changing dynamics of the power system and provides a more certain and enduring degree of access to their regional reference node. Congestion fees attempt to achieve a similar result, however, are reliant on a centralised view of congestion levels into the future. This creates a risk for investors that their revenues may be cannibalised by the connection of subsequent projects. This is particularly the case if the connection fees for subsequent projects are set too low to deter inefficient investments. Due to these differences, the priority access model should also result in a much lower cost of capital than under congestion fees or the status quo.
- **Market-based solution** – A priority access model will enable investors and market participants to estimate their own access under the prescribed framework, rather than have a centrally determined congestion charge. This will be particularly supported by an enhanced approach to information provision for prospective generators, who will retain a high degree of autonomy in their investment decision making and will be better equipped to determine whether they can or cannot internalise the costs associated with potential future congestion.
- **Concerns around the workability of congestion fees** – a congestion fee may sound straight forward in practice, however, the ability to adequately and accurately model, assess and allocate congestion cost on to a new entrant represents an impossible task. Multiple delays in anticipated delivery of a modelling report alongside the directions paper is indicative of the challenge of the task and likely ongoing difficulty for any organisation administering the scheme. There is a high risk that this congestion fee would evolve into an administratively cumbersome process which could act to slow new investments and connections, and likely increase costs to consumers.

Detailed questions

Allocation mechanism

Question for stakeholders

Q9. Should the ESB work towards providing as many unique queue numbers as is feasible (given implementation challenges) or is a tiered approach preferable?

Hydro Tasmania supports the ESB working towards a relatively granular approach for allocating queue numbers, with the proposed batching approach representing a sensible middle ground. The risk with a less granular approach is that it smears congestion cost across different generators and makes it more difficult for new investments in determining the level of access they will be able to achieve. Conversely, 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. For example, it may create unreasonable risk for new investments if a generator meets its queue criteria one day after another generator connecting in the same area but is not provided the same level of access.

We also suggest that a tiered approach with periodic reviews is not favourable as it introduces unnecessary complexity and uncertainty into the process. When a generator retires and relieves congestion, generators with higher queue numbers are likely to benefit from the reduced congestion without needing an administrative decision to determine whether a generator should be promoted to a lower queue number.

Questions for stakeholders

Q10. What mechanism should be used to allocate queue positions to generators? E.g. first come first served, auctions, a combination or another approach?

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.

Questions for stakeholders

Q15. At what time within the connection process should the queue position or congestion fee be locked in?

We are broadly supportive of the ESB's proposal that connection applicants receive an indicative queue position and/or congestion fee in response to their connection application, with the outcome to be finalised upon completion of the connection agreement.

Any process must ensure that projects with long construction times receive an appropriate queue position upon reaching final investment decisions and commencing construction. For instance, Hydropower assets can take up to 5 years in planning and development phases before reaching FID, including substantial feasibility studies, environmental impact assessments, and so on. This is in stark contrast to wind and solar developers, who can reach FID within a much shorter period. On this basis, we strongly encourage the ESB to avoid setting a uniform and single set period for the determination of queue positions.

Questions for stakeholders

Q19. Once set, parties would be expected to progress to implementation. Should there be time limits or expiry dates for projects which do not progress in a timely manner? If so, what time limit would be appropriate?

We support the principle of removing queue positions where projects are not progressing in a timely manner. Without such a provision, projects that are never progressed may act as a barrier to entry to other projects seeking to connect in a similar part of the grid. However, discretion should be provided to the administering body such that projects are not unduly penalised for unavoidable delays and force majeure events.

Duration of rights

Questions for stakeholders

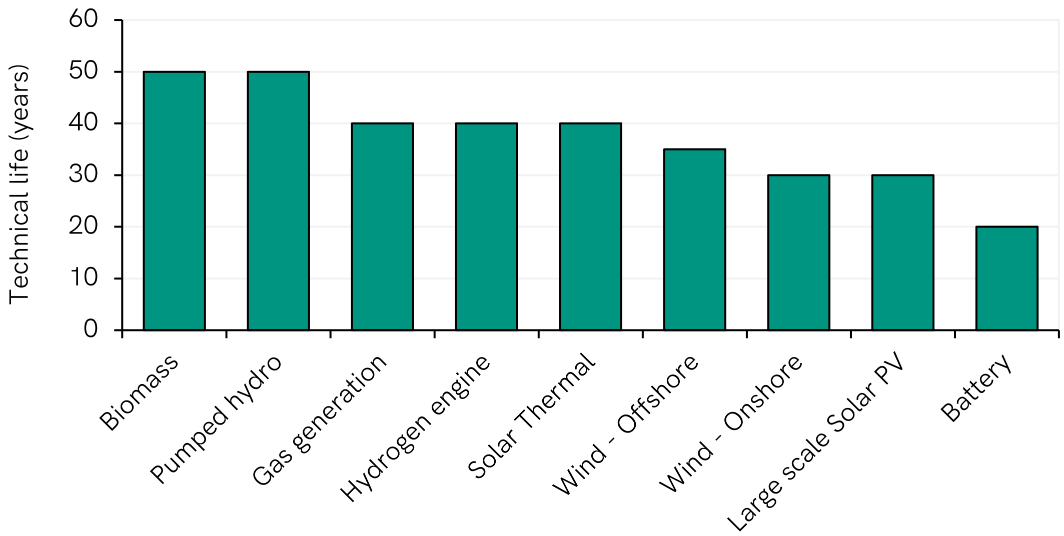
Q11. Would stakeholders prefer that the priority access rights (i.e. queue positions) be set for: the life of the participant's asset, a fixed duration, or a fixed duration with a glide path?

Q12. If set for a fixed duration, what period of time do stakeholders consider would be most appropriate? Should this period be adjusted if combined with a glide path?

One of the primary benefits of the priority access model is that it places the congestion risk on the party best placed to manage the risk – newly connecting generators. In doing so it provides both new and existing generators with far greater certainty on their level of access to the regional reference price, resulting in lower capital costs for new projects, refurbishments, and upgrades.

Our preference is for assets to be provided with priority access for a fixed duration, with the duration set in reference to the asset's life. For example, a pumped hydro generator would receive priority access in proportion to its typical technical life of 50 years, while a battery would receive priority access in proportion to its typical asset of 20 years. Figure 2 shows typical technical lives for different technology types as assumed by AEMO.

Figure 2 Technical life of different technology types (AEMO 2022)



A uniform and set duration for access rights would be entirely inappropriate, on the basis that different generator types, both existing and new assets will have different asset lives, different scale of capital required, and varying payback periods. For example, under 20 years of priority rights a battery may be covered for its entire technical life helping de-risk the asset, whereas this may only cover 40% of the technical life of a pumped hydro asset. This means that a fixed duration of priority rights would skew the market towards only building comparatively shorter-lived assets, resulting in an inefficient technology mix and higher overall costs to consumers.

Providing priority rights for a fixed period with or without a glide path (say 15 years) that is shorter than an asset's life would have drawbacks for both the generator and the system. For the generator it would re-introduce a high level of uncertainty regarding access to RRP. The system-wide benefit of the new policy would also reduce because after expiry of priority access rights, congestion risk would return to the status quo arrangements where a newly connecting generator does not necessarily face the cost of the congestion it creates and can cannibalise revenues of existing generators.

An alternate metric to duration-based priority access is to provide access in proportion to a generator's capacity. For example, 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.

Treatment of incumbents

Question for stakeholders

Q20. Do stakeholders have a preference for any of the options listed above regarding the treatment of incumbents in transitioning to the priority access variant? Are there alternative options for the treatment of incumbents under this model that the ESB should consider?

A key aspect of the priority access model is shifting congestion risk to parties best placed to manage it – newly connecting generators. To achieve such an outcome requires existing generators to receive a position at the front of the queue ('queue position zero').

The ESB have noted that providing existing generators full access in perpetuity would come at the expense of new entrant's ability to be dispatched in the energy market, and that a range of measures are being considered to achieve an appropriate balance between new and existing assets. Hydro Tasmania is supportive of ESB's considerations in this area, but care needs to be taken to ensure that any measure introduced to achieve such balance does not undermine the many benefits of the priority access model including its ability to provide greater certainty (and potentially lower cost of capital) for new projects and to lower congestion costs (and in turn consumer costs) by encouraging more efficient use of the network. Specific comments on options proposed by the ESB are below.

1. ***The queue position allocated to incumbents upon introduction of the new access framework could expire at a specified date.***

   This proposal has merit, but only if a bespoke term is referenced rather than a common pre-determined date. If a common pre-determined date was used, then effectively the priority access model would revert to the status quo at that point, eliminating the newly created congestion signals for newly connecting generators. A bespoke term would avoid unintended consequences such as disadvantaging technologies with longer asset lives (discussed in more detail in Question 11). Establishing a bespoke, but fixed term of access would also provide new investments replacing existing assets with greater certainty on market access.

Hydro Tasmania

An alternative to this approach would be to provide incumbents indefinite priority access, but only for a proportion of their capacity. Our thinking on this proposal is covered in more detail in Question 11.

2. ***Incumbents, or certain types of incumbents such as fossil fuel generators, could not receive grandfathered rights.***

   A fundamental pillar and principle to guide market reforms in the NEM should be to ensure technology neutrality as far as is practicable. Hydro Tasmania's view is that any future NEM market design should support the transition of the energy sector to cleaner energy sources and avoid retaining emissions-intensive generation in the market longer than is necessary. However, in the case of transmission access reform, there does not appear to be a clear policy rationale for excluding fossil generators from receiving priority access rights. Hydro Tasmania considers that pursuing targeted emissions reductions in the sector would be better achieved in other areas of market and government energy policy.

   Being that grandfathered rights cannot be 'commoditised' (i.e. withheld and traded), it is difficult to see how the grandfathering of access for incumbent generators would provide an unfair advantage to ageing thermal assets, or prolong the decarbonisation of our power system. Regardless the duration of access rights, the key driver for the retirement of ageing thermal assets will be the natural end of their technical and economic life, and changes in the RRP will be a much stronger driver on closure decisions than market access.

3. ***The queue position allocated to incumbents could gradually increase over time to reflect the erosion of access that might be anticipated under the status quo.***

   Hydro Tasmania does not support this measure with our rationale outlined in our response to Question 11.

4. ***The queue position allocated to incumbents could gradually dilute over time by including a pre-determined quantity of new generation capacity within the same queue number or tier.***

   Hydro Tasmania does not support this proposal as it erodes one of the key advantages of this model, being the ability to lower congestion costs (and in turn consumer costs) by encouraging more efficient use of the network.

5. ***The initial queue position allocated to incumbents could be adjusted to reflect transmission expansions, in order to avoid a windfall gain associated with improving their level of access beyond their position at the time the new access arrangements are implemented.***

   We do not support this proposal. Existing generators with low queue positions would already have full access to the RRP, so a transmission expansion will not benefit them, rather generators further down the queue would benefit. Determining the 'level of access' a particular project expected when connecting is an impossible task and it is unlikely that adjusting queue positions would improve efficiency or distributional impacts.

6. ***Incumbents could have the option of paying to maintain their queue position, and if so how this would interact with the broader approach to allocating queue positions.***

   We do not support this approach as it would introduce many of the deficiencies of the congestion fee model into priority access. These include the deficiencies of a point in time projection of future congestion risk and cost, the difficulty in determining the appropriate level of payment. Further, such an approach would erode the newly created congestion signal in the priority access model.

Appendix 4 – Quantitative analysis of existing levels of variable renewable energy (VRE) curtailment arising from thermal congestion

In the many years of debate on Transmission Access Reform, we have not seen comprehensive analysis on the actual level of thermal congestion in the grid and how this is expected to change over time. To contribute to the ESB's and industry's thinking on this important reform, we have developed a methodology for estimating the amount and cost of wind and solar output curtailed due to thermal congestion. Results and methodology are presented below.

Methodology

Table 4 Thermal curtailment methodology

Step	Task	Details
1	Estimate curtailment	We define curtailment as the difference between availability and total cleared for each DUID (semi-scheduled generators only). We collect 5-minute data on availability and total cleared from the AEMO's DISPATCHLOAD table.
2	Obtain thermal constraint data	Top ~250 binding thermal constraints are identified by filtering AEMO's DISPATCHCONSTRAINT table for constraint IDs containing the character ">", which identifies a thermal constraint and marginal values <> 0.
3	Determine VRE generators most affected by a given thermal constraint	For the top 250 binding thermal constraints, we identified the 4-5 VRE generators with the highest coefficients. This means each VRE generator is assigned a specific set of thermal constraints which affect them.
4	Obtain NEM price data	Uses AEMO's TRADINGPRICE table: at 30-minute intervals for time periods prior to the introduction of 5MS (on 1 October 2021) and DISPATCHPRICE table 5-minute intervals following the introduction of 5MS
5	Estimate curtailment amount due to thermal constraints - DUID	Bringing steps 1-3 together, on a DUID-by-DUID basis we identify dispatch interval in which a VRE generator is curtailed **and** a thermal constraint specific to that DUID is binding **and** the RRP is greater than zero (as to not capture economic curtailment and/or output that is negatively valued by the market).
6	Calculate curtailment cost	Calculated as the amount of thermally curtailed output multiplied by the price divided by either 2 or 12 (2 prior to 5MS and 12 post 5MS). Here we cap the price at $500/MWh as to remove the effect of extreme market volatility.
7	Regional assessment	DUID-based data from steps 6 and 7 is summed on a regional and monthly basis to determine monthly regional estimates.

Amount and cost of thermal curtailment by region

Figure 3 shows that average curtailment across the NEM is increasing, reflecting new solar and wind farms entering the market. In 2022, VRE curtailment due to thermal constraints has increased to 28 MW on average, up by 235% on levels in 2020 and 2021. This is still at very low levels but demonstrates the potential for step-increases in thermal curtailment over relatively short periods.

The chart also shows that the level of curtailment is affected by seasonality, with higher levels of curtailment occurring in sunnier months between September to March. This seasonality reflects the higher levels of solar availability during those months and associated thermal congestion. The highest levels of thermal curtailment occur in New South Wales, followed by Victoria.

Figure 3 Monthly average thermal VRE curtailment by NEM region

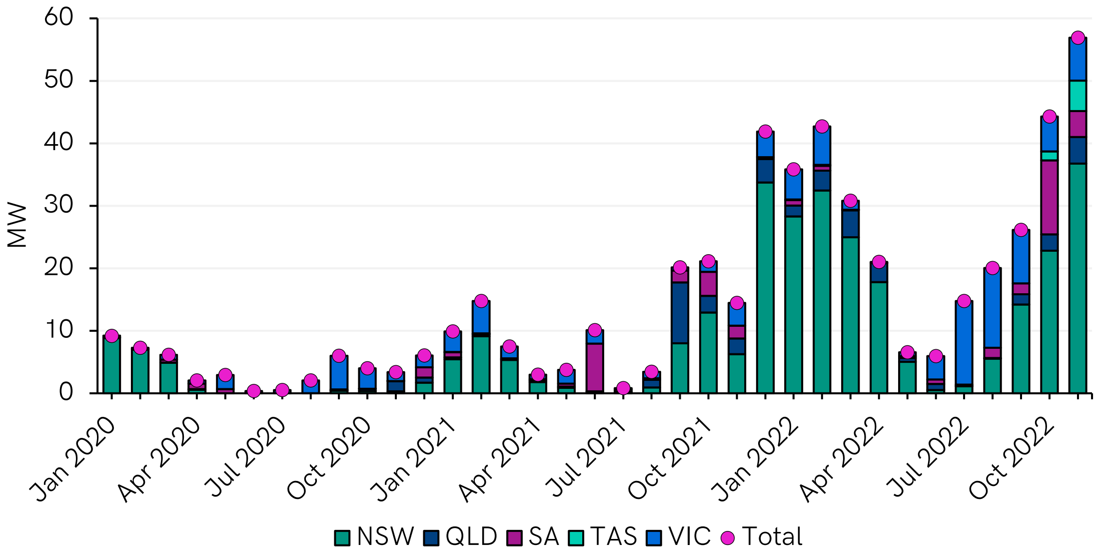
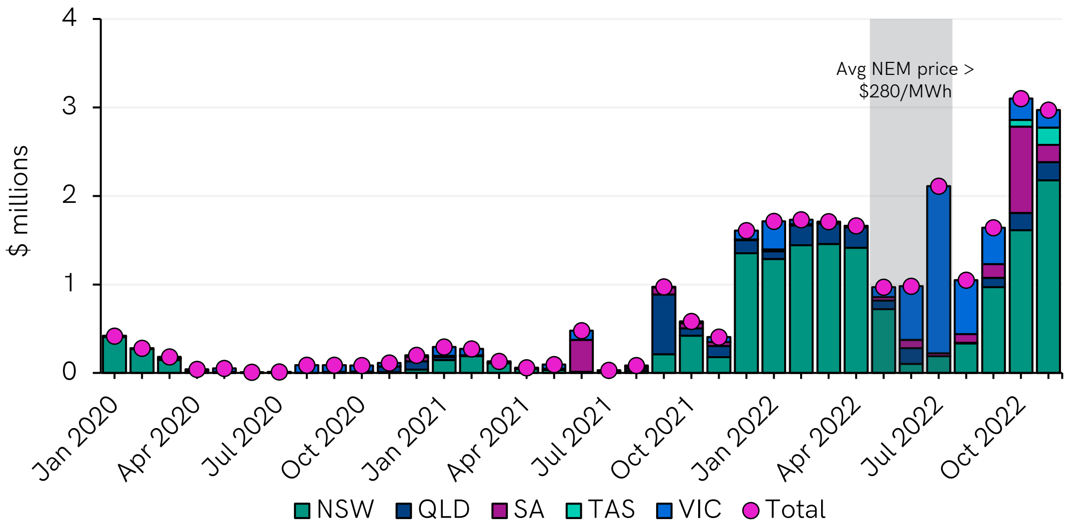


Figure 4 shows that the cost of curtailment largely follows the pattern observed for the average level curtailment. That is, the cost of thermal curtailment in 2022 has increased to $20 million, around 3 times higher than in 2020 and 2021 combined. This reflects both higher levels of thermal curtailment and high NEM prices 2022.

Figure 4 Monthly average thermal VRE curtailment cost by NEM region



Most common thermal constraints in 2022

Table 5 shows that binding thermal constraints occur most frequently in NSW. Molong Solar Farm has a coefficient of 1.0 in the N>>N-NIL_94T constraint (ranked 1st) meaning it is likely to be constrained off when this constraint binds. In Victoria, the V>>V_NIL_18 constraint (ranked 11th) constrains off Ararat Wind Farm which has a coefficient of 1.0. The Q>NIL_EMCM_6056 constraint (ranked 2nd) likely has a smaller impact on curtailment compared to other constraints when it binds as it constrains only Emerald Solar Park to 68 MW from its capacity of 72 MW.

Table 5 Top 10 thermal constraints by % of DIs in 2022 (to December)

Rank	ConstraintID	% of DIs in 2022	High coefficient semi-scheduled generators
1	N>>N-NIL_94T	10.1%	Molong Solar Farm (NSW) Manildra Solar Farm (NSW)
2	Q>NIL_EMCM_6056	9.5%	Emerald Solar Park (QLD)
3	N>>N-NIL_969	7.0%	Gunnedah Solar Farm (NSW)
4	N>NIL_94T	6.1%	Molong Solar Farm (NSW) Manildra Solar Farm (NSW)
5	N>NIL_969	5.3%	Gunnedah Solar Farm (NSW)
6	Q>NIL_YLMR	4.5%	Yarranlea Solar Farm (QLD) Maryrorough Solar Farm (QLD)
7	N>>N-NIL_94K_1	4.1%	Suntop Solar Farm (NSW)
8	N>N-NIL_997_99A	3.8%	Corowa Solar Farm (NSW)
9	N>NIL_94K_1	3.8%	Suntop Solar Farm (NSW)
10	N>NIL_997_99A	2.9%	Corowa Solar Farm (NSW)
11	V>>V_NIL_18	2.7%	Ararat Wind Farm (VIC)

Highest level of curtailment by thermal constraint in 2022

Table 6 shows that binding thermal constraints lead to high levels of curtailment in NSW. We estimate that the two highest ranked thermal constraint – N>>N-NIL_94T and N>NIL_94T – led to a combined 82 GWh of curtailment in 2022 (to December). Molong Solar Farm has a coefficient of 1.0 in both of these constraints while Manildra Solar Farm has coefficients of 0.8796 and 0.8731 in the N>>N-NIL_94T and N>NIL_94T constraints respectively – meaning that they are likely to be constrained off when this constraint binds.

Table 6 thermal constraints by amount of curtailment in 2022 (to December)

Rank	ConstraintID	Curtailment (GWh)	High coefficient semi-scheduled generators	Region
1	N>>N-NIL_94T	50	Molong Solar Farm Manildra Solar Farm	NSW
2	N>NIL_94T	32	Molong Solar Farm Manildra Solar Farm	NSW
3	V>>V_NIL_18	26	Ararat Wind Farm	VIC
4	N>>N-NIL_94K_1	10	Suntop Solar Farm	NSW
5	V>>V_NIL_9	9.6	Ararat Wind Farm	VIC
6	N>NIL_94K_1	8.6	Suntop Solar Farm	NSW
7	Q>NIL_EMCM_6056	8.1	Emerald Solar Park	QLD
8	N>>N-NIL_969	7.7	Gunnedah Solar Farm	NSW
9	N>N-NIL_997_99A	6.8	Corowa Solar Farm	NSW
10	Q>NIL_YLMR	6.7	Yarranlea Solar Farm Maryrorough Solar Farm	QLD

Highest cost of curtailment by thermal constraint in 2022

Table 7 shows that 5 of the top 10 constraints by curtailment cost affect primarily NSW generators. This table is broadly consistent with the ranking of thermal constraints by amount of curtailment in 2022.

Table 7 thermal constraints by cost of curtailment in 2022 (to December)

Rank	ConstraintID	Cost of curtailment ($)	High coefficient semi-scheduled generators
1	N>>N-NIL_94T	$4,252,006	Molong Solar Farm (NSW) Manildra Solar Farm (NSW)
2	N>NIL_94T	$2,722,757	Molong Solar Farm (NSW) Manildra Solar Farm (NSW)
3	V>>V_NIL_18	$2,481,580	Ararat Wind Farm (VIC)
4	V>>V_NIL_9	$939,376	Ararat Wind Farm (VIC)
5	N>>N-NIL_94K_1	$931,429	Suntop Solar Farm (NSW)
6	N>NIL_94K_1	$754,573	Suntop Solar Farm (NSW)
7	Q>NIL_EMCM_6056	$657,517	Emerald Solar Park (QLD)
8	S>>X_RBPA+RBTX2_06	$619,673	Hallett 2 Wind Farm (SA)
9	N>>N-NIL_969	$581,440	Gunnedah Solar Farm (NSW)
10	V>>V_NIL_7	$534,385	Ararat Wind Farm (VIC)

Highest level of thermal curtailment by Generator in 2022

Table 8 below shows that NSW generators make up 7 out of the top 10 DUIDs ranked by GWh curtailed by thermal constraints. Ararat Wind Farm also saw significant GWh curtailment of which a large proportion was likely due to the V>>V_NIL_18 constraint.

Table 8 level of curtailment by DUID in 2022 (to December)

Rank	Generator	GWh curtailed	Region
1	Manildra Solar Farm	35	NSW
2	Ararat Wind Farm	32	VIC
3	Molong Solar Farm	27	NSW
4	Goonumbla Solar Farm	19	NSW
5	Gunnedah Solar Farm	14	NSW
6	Parkes Solar Farm	13	NSW
7	Suntop Solar Farm	13	NSW
8	Corowa Solar Farm	8.3	NSW
9	Emerald Solar Park	8.1	QLD
10	Yarranlea Solar Farm	6.2	QLD

Highest level of % availability curtailed by Generator in 2022

NSW generators also ranked highly in terms of the amount of thermal curtailment as a percentage of their availability (see Table 9). The N>>N-NIL_94T and N>NIL_94T constraints are the likely causes of thermal curtailment of output from Molong and Manildra Solar Farms.

Table 9 Top 10 thermally curtailed duids (as a % of availability) and GWh curtailed in 2022 (to December)

Rank	Generator	GWh curtailed	% curtailed	Region
1	Molong Solar Farm	27	46.2%	NSW
2	Manildra Solar Farm	35	42.0%	NSW
3	Corowa Solar Farm	8.3	16.1%	NSW
4	Goonumbla Solar Farm	19	13.9%	NSW
5	Parkes Solar Farm	13	13.2%	NSW
6	Ararat Wind Farm	32	6.8%	VIC
7	Gunnedah Solar Farm	14	6.1%	NSW
8	Emerald Solar Park	8.1	5.4%	QLD
9	Suntop Solar Farm	13	4.5%	NSW
10	Yarranlea Solar Farm	6.2	3.0%	QLD