10th June 2022

Energy Security Board
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Submission to the Energy Security Board in response to the Transmission Access Reform Consultation Paper

Please find attached a public submission for the consideration of the ESB.

Yours sincerely,

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Transmission Access Reform

Finncorn Consulting's response to the ESB's Consultation Paper

Released as a public submission

10th June 2022

1. Introduction

Finncorn has been engaged by Energy Consumers Australia ('ECA') to continue working with the ESB and other stakeholders in relation to transmission access reform ('TAR') in the ESB's Technical Working Group ('TWG'), and to provide advice to ECA on this topic.

We understand that ECA will incorporate or reference this submission with their own response to the Consultation Paper ('CP').

1.1 Progress is being made

Following the Post-2025 process and associated stakeholder submissions one year ago, the ensuing period has allowed for a broader discussion on TAR via the TWG and associated activity. This has included the consultative development of:

1. **Case for Change:** A more clearly articulated, forward-looking explanation of the 'why' (Part 2 of the CP) which stresses even more clearly the urgency of an adequate market design to support an efficient transition.[1]
2. **Objectives and Assessment Criteria:** an enhanced set of objectives for TAR reform, and criteria against which candidate models for reform will be judged (part 1.3 of the CP).
3. **Wide consultation on alternatives:** a stakeholder-led broadening of the TAR options, alongside the withdrawal of some previously-proposed alternatives (such as CMM-REZ). This has led to reconsolidation to the candidate four models, two of which have been proposed by market participant stakeholders representing the incumbent generation industry.

1.2 Enhanced focus on key issues

This has been a valuable process, and we note the following important results:

- Greater focus on the essential role of **new-entrant storage and flexible load** as an element of the lowest-cost future system.[2] This has appropriately balanced some louder and more numerous voices representing incumbent variable renewable energy investors and operators.
- Acknowledgement of our concern raised in the Post-2025 process that the **current market design is critically at odds with the ISP**, which consumers rely upon to plan the delivery of a reasonably efficient generation, storage and transmission system for the energy transition [3]. This includes the location of storage and flexible load, where (CP, p20) "*The ISP suggests utility scale storage should be mostly located in REZs so that it can offset the need for transmission investment; charging up on low cost and low emission generators which would otherwise be constrained and discharging when the output of these generator reduces as the sun sets or the wind dies down. However, under the current market design, **this plant may be rewarded for competing with and displacing VRE during periods of congestio**n.*" (our emphasis). This is a point we have made in the past[4] and it very important that this is now more clearly recognised in the case for change.
- Noting the essential requirement of promoting **effective competition** via appropriate market design – by reducing investor risk (and cost of capital) associated with the weaknesses of the status quo, and in the ESB's words, achieving "*… a level playing field that balances investor risk*

[1] Very well summarised in the CP, p10: "*Access reform seeks to address the current market design limitation whereby congestion costs are caused by a producer but are not borne by the producer.*" Indeed. They are borne by consumers.

[2] Captured explicitly in the ESB's fourth objective, where they note (CP, p10): "*… the importance of providing signals for technologies that can alleviate congestion, both in operational and investment timeframes. This includes, for example, grid-scale battery storage and demand-side resources, including hydrogen. The role of such technologies is important in facilitating the current energy sector transition in a way that ensures **efficient network utilisation** and, in turn, that **consumers pay no more than necessary**.*" Our emphasis.

[3] Section 2.1 of the CP: "*the current market design systematically incentivises generation investment at locations that are inconsistent with the least cost development path identified by the ISP. This is because generators are paid the RRP, which does not reflect the marginal cost of energy at their specific location. To the extent that generation investment occurs at certain locations in excess of the level identified in the ISP, congestion is likely to further increase.*"

[4] See our commentary here: https://www.dragomanglobal.com/sites/default/files/2021-11/David_Heard_LMP.01.pdf

with the continued promotion of new generation and storage entry that contributes to effective competition, reliability and system security in the long-term interests of consumers."

1.3 Consistency with our Post-2025 position

The relevant part of our submission one year ago to the Post-2025 process is include as Appendix 1.

Our views have not changed at this point. The candidate models which appear best-placed to meet the objectives and assessment criteria remain:

- **Congestion Management Model (with universal rebates) ('CMM')** – this has been sensibly adjusted for universal rebates rather than a direct link to REZ design, and appears attractive with the caveat that optimising the rebate allocation methodology is an important element of the upcoming period of detailed design.
- **Connection Zones with Connection Fees ('CZ+CF')** – an administrative mechanism for pre-paying the cost of inefficient levels of congestion, funded by the assets which cause it, with the value returned to consumers via an offset to TUOS costs. We remain surprised market participants appear to have rejected our preferred market-based alternative of congestion being transparently priced and risk-managed via FTRs, but unless those views have changed, connection fees – while subject to forecasting risk – have the potential to broadly identify and capture the cost of congestion and therefore provide the necessary investment timeframe price signal.

1.4 New-entrant market conditions remain a concern for other models

Other elements of our Post-2025 views which have not changed remain of concern – in particular our view that efficient, competitive markets are essential to ensure the lowest-cost system eventuates AND that the benefits of this are passed through to consumers, not retained by investors or intermediaries as excess return.

The status quo certainly does not provide this, with beggar-thy-neighbour behaviour encouraged among generators, and completely inappropriate price signals for congestion-relieving assets behind constraints, as clearly described in the CP.

The antidote to both of these is appropriate and transparent pricing of congestion via exposure to locational marginal pricing – even if the settlement residue is distributed back to participants, the operational and investment timeframe price signals are likely to be very effective.

We are not convinced that in investment timeframes, the **Transmission Queue** ('TQ') is an adequate price signal compared with the clarity of a fee related to the cost of the caused congestion. This concern is magnified by the substantial complexity it appears to add to the project development process, including unresolved issues in relation to how queue positions may be held if projects are delayed, or whether they can or should be traded. There is no apparent advantage to this complexity in our view.

In operational timeframes, the **Congestion Relief Model** ('CRM') also appears to suffer from the problem of complexity, uncertainty and cost of implementation, compared with the CMM. And again, there appears to be little benefit compared with the CMM, especially given the uncertainty of uptake of a voluntary mechanism among incumbents.

We have been forced to wonder, would the CRM eliminate the race-to-the-floor bidding behaviour that causes inefficient operational dispatch, and is the key symptom of the flawed status quo approach to transmission access? We have seen no evidence to suggest it would. Rather, CRM appears more suited as an incremental opportunity for incumbent generators to trade among themselves to optimise their dispatch against their contract positions and the RRP.

If that is its purpose, there is nothing particularly wrong with that, but as a voluntary market it does NOT provide the very transparent and certain underpinning for new-entrant investments in storage and responsive loads to locate and operate where, at times, the marginal value of constrained energy is zero. As a result, it does not appear well-matched to the objectives of TAR as set out in the CP.

1.5 Next steps are critical: evidence-based policy

At this stage, the strongest evidence base both against the status quo, and for an alternative model, is the analysis prepared by AEMC to support CoGaTI, and the subsequent August 2021 FTI Consulting work on congestion for the ESB.

Consumers are critically interested in securing the benefits proposed from this analysis, delivered as the efficient pass-through of lower systems costs than the status quo.

As a result, we expect that the reform proposal presented to Ministers will be one which is:

- Sufficiently developed and detailed to be well-understood and assessed by stakeholders;
- Supported by rigorous and consistent modelling of system-level costs and benefits for all the four candidate models and the status quo counterfactual; and
- The most attractive choice among the current candidate models, having regard to this modelling evidence base as well as broader evaluation against the objectives and assessment criteria set out in section 1.3 of the CP.

For this reason, we are NOT categorically stating that the 'best' choice is CZ+CF and CMM. Given the information at hand, these options appear materially better than the alternatives proposed by stakeholders and the ESB. However, we remain open to evidence to the contrary.

Because the CRM provides a partial, voluntary market with substantially higher implementation costs, and less transparent price signals for new entrant storage / flexible load investment, we anticipate that it, in particular, has a very challenging path to outperform CMM on any even-handed modelling of the alternatives.

1.6 Does Labor's Rewiring the Nation policy change the situation?

Despite some arguments being advanced by some stakeholders following the Federal election, we are very firmly of the view that no, it certainly does not. Labor's election victory does not negate the case for change at all.

There is no evidence whatsoever that Labor is proposing to over-invest in transmission infrastructure to the point that congestion is an irrelevance in the future energy system.

In fact, it is very clear that Labor's policy intent[5] is to support the delivery of the ISP, by addressing perceived process and regulatory obstacles to timely delivery of ISP projects.

This is welcomed, as we believe it is in consumers' interests for the ISP to be delivered on schedule, provided we can be confident that the ISP does in fact represent the least-cost system plan.

According to Labor, the proposed Rewiring the Nation Corporation would "*partner with industry and provide low cost finance to build the ISP*".

Given this is the policy objective, note that the Draft 2022 ISP indicates that in 2040, **the least-cost system includes around 12% of the current NEM demand being either spilled or curtailed**[6], which highlights the fact that congestion is an essential characteristic of a high-VRE system at a fair cost to consumers, not some symptom of regulatory gridlock in transmission investment.

In previous advice we have supported the judicious use of the government's financial capacity and low cost of capital to support challenging infrastructure deployment, including REZs and electricity transmission, provided it is done equitably across the board (rather than 'picking winners'). From what we can see from the Labor policy, this is the case, as it make clear it will be guided by the ISP, not favoured projects outside that rigorous framework.

[5] https://alp.org.au/policies/rewiring_the_nation

[6] Refer to CP Figure 5: ~2.5% curtailed, ~9% spilled. At an average 30% capacity factor for the ~75GW of utility scale VRE in 2040, this is over 20 TWh of energy.

Rewiring the Nation, even if only a form of financial support to existing investors in existing ISP projects, represents some transfer of the cost of the investment from energy consumers to taxpayers. That may well be appropriate – but noting the very substantial overlap of these groups.

Labor was elected partly on a promise to spend more effectively. If that is the case in this instance, then Labor will be critically concerned to ensure that any investment they make or support via Rewiring the Nation will be efficient in its size, and utilised most effectively over its life.

As the CP notes (p7), "*In the medium to long term, the NEM's version of open access is incompatible with REZs because it is an unstable foundation for co-ordinated system development*"

As a result we are very confident the Labor government is now an even more closely-concerned stakeholder in the delivery of transmission access reform.

2. Assessment of Candidate Models

In this section, we provide some further details on our views of the four candidate models in the CP.

2.1 Congestion Zones with Connection Fees (Investment Timeframe)

We focus on the Connection Fee – recognising that the concept of Connection Zones is more related to the sensible provision of information to investors – and thus we support concepts such as Iberdrola's proposed Transmission Statement of Opportunities in defining what is meant by 'Connection Zones'.

2.1.1 The essential locational price signal for investors (and thus, consumers)

The strength of the Connection Fee model is the clear and strong locational price signal, to ensure assets are built in the right places relative to their impact of congestion in the system.

To be an effective price signal, the connection fee must be clearly related to the present value of the cost of congestion created by the proposed connecting asset, as proposed by the ESB (CP, p27).

To the extent this cost exceeds an acceptable level (for example, the optimally-designed congestion expected within a REZ), the fee would ensure the connecting asset 'funds' the inefficient cost of congestion. This may be literal, via TNSP use of the funds to deploy additional infrastructure to reduce future congestion, or indirectly via reduced TUOS costs passed through to consumers if such physical investment is not determined to be justified under the RIT-T.

The price signal should therefore strongly discourage excessive generation capacity relative to transmission, and so protect incumbents from the cannibalisation which can freely occur under the status quo, when generation capacity is able to subsequently locate and claim a share[7] of the constrained transmission.

2.1.2 Complexity is a challenge, but some distinctions are necessary

The weakness of the Connection Fee model is the need for a balance in such an administratively-determined forecast, between accuracy and complexity.

There is some risk of mistaking precision for accuracy here – all forecasting will be wrong, it is just a question of by how much. That suggests leaning towards a simpler, more pragmatic approach to setting connection fees that are broadly, directionally accurate on a geographic basis, rather than overly precise. Equally, a batching process to apply a given connection fee to a given capacity in a location would be pragmatic in ensuring connection fees are not altered with every individual commitment of capacity.

By contrast, the most important aspects of fee design relate to the type and dispatch behaviour of connecting assets, where some complexity is likely to be necessary.

This particularly relates to the difference between types of variable renewable energy and firmer assets (including storage, demand response and traditional dispatchable generation).

Clearly, it is possible for firmer assets to operate in such a way as to avoid contributing to congestion - but that is not what we should expect, at times when a high RRP is on offer beyond a constraint.

In our view it would be fair for such assets to be offered a choice between either a lower (or zero) connection fee with obligations not to be dispatched in competition with renewables, or to face the identical locational price signal.

Equally, the prospective impact of a solar farm on congestion in an area with existing solar capacity may be much more significant than the impact of a windfarm, particularly if the location is expected to be relatively windy in darkness.

Therefore, if the price signal from the Connection Fee to be reasonably effective, it will need to distinguish between broad classes of asset and their associated generation profiles, including (for firmer capacity) the potential for investors to trade off the size (or existance) of the fee against restrictions on dispatch during times of congestion.

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[7] Potentially an outsized share if they pick the ideal location in terms of their generation coefficient, as noted in the CP's section 2.2.

2.1.3 Consultation Questions on Congestion Zones with Congestion Fees

1.0. What form of incentive should be used to influence generator location decisions?	In the absence of a market-determined assessment of congestion costs (such as traded FTRs), a connection fee based on a reasonable forecast of the inefficient cost caused by a connecting asset. The same principle should apply for other assets, including storage, if it is possible they may not operate to relieve congestion, but to worsen it. Equally, if any such assets make enforceable commitments to operate in a manner that does not worsen congestion (i.e. agree not to be dispatched beyond the point of causing a constraint), a connection fee should not apply.
1.1. What methodology should be used to calculate the efficient hosting capacity of the network for each zone?	A relatively simple methodology, recognising that precision in forecasting long-term congestion is unlikely to be high. At a geographic zone level, the investment price signal needs to be clear and robust, but likely does NOT need to be highly complicated in order to be effective.
1.2. How does this methodology reflect differences in the output profiles of different generator types?	Complexity is more appropriate in assessing differences in fees for different profiles. There are likely to be a handful of similar profiles to be treated similarly as a group, but differentially from other profiles. These may be solar PV, wind, 'unconstrained' dispatchable capacity (including storage) likely to compete for congested dispatch, and 'constrained' dispatchable capacity which has committed NOT to compete for congested dispatch.
1.3. How should the model treat multiple generators seeking access to the same part of the network?	To reduce uncertainty and encourage efficient deployment, a batching process – which allows for a specified quantity of new capacity to access a given connection fee before any reforecasting occurs – seems pragmatic.
1.4. Who should be responsible for administering various aspects of the framework?	No opinion.
1.5. How should connection fees be calculated?	See 1.0 above – NPV of inefficient cost of congestion caused.
a. What is the correct balance between accuracy and simplicity/transparency?	See 1.1 and 1.2 above – fairly broad and simple by geographic zone may be adequate, and may offer transparency via consistency with the proposed Transmission Statement of Opportunities. Some important distinctions in the connection fee are likely to be required based on a handful of meaningfully different output profiles within such zones.
b. What should happen to revenue paid by generators?	Received by TNSP as an offset to regulated opex. This would thereby reduce consumer costs as an offset to the inefficiency of the introduced congestion, and may also provide a source of funding for any regulated network investment by the TNSP, including any such investment triggered by the connection (by 'flipping the RIT-T': creating a sunk capacity cost that may mean a transmission enhancement to reduce the caused congestion may show a net benefit once that sunk cost is excluded).

2.2 Transmission Queue (Investment Timeframe)

We appreciate that on the face of it, if transmission queue positions were reflected in operational outcomes under congestion (such as lack of access to rebates under the CMM), this could resemble an effective locational price signal.

However, we do not think it is likely to be an efficient means to create this price signal, compared with connection fees.

2.2.1 Complex, with obvious risks of unintended consequences

One concern is related to the allocation of the queue positions, with the substantial complexity of the proposed 'EOI process', the 'safety-valve process' and its associated 'new regulatory process … with oversight of TNSP charges, timeframes and contract terms'.

This is a substantially more complex regulatory framework for investment than the clarity of a posted schedule of connection fees.

There also appears to be a clear risk of unintended consequences. An example is projects securing a favourable queue position and then failing to proceed at the pace expected – which may create an overall bottleneck in investment if projects with better overall prospects are unable to take their place due to a less-favourable queue position.

The model therefore appears to run the risk of creating a new type of obstacle to efficient investment – or at best, a shadow market in trading queue positions between projects (which we suspect is not indicative of a more efficient market for capacity investment).

We appreciate that these weaknesses have been identified by the ESB and the Technical Working Group (refer CP, p37) but given the model is on a very short shortlist, it is important these significant flaws are not dismissed as minor details.

2.2.2 Appears to fail tests of encouraging right type of capacity, utilising transmission

The model appears to be designed to resolve priority between competing proposed renewable energy capacity, and in that sense, it is very much backwards-looking at the 'pre-storage' phase of the NEM.

In our view, it does not address the objective of 'maximising hosting capacity of available transmission' at all (refer CP, p36), instead suggesting the answer is to just build more!

There is no mention of making distinctions between variable and dispatchable capacity, or even between different types of variable renewables – essential in relation to the actual impact of congestion. This cannot be captured in an integer queue position.

2.2.3 Consultation Questions on Transmission Queue

2.1. How should a generator's queue position manifest in operational timeframes?	Limited right to CMM rebates until all other assets with lower queue positions are placed in a net position (after LMP + rebate) that is no worse than if the higher queue position assets were not dispatched.
2.2. What methodology should be used to calculate the efficient hosting capacity of the network (for the purposes of establishing whether initial queue positions are available)?	A relatively simple methodology, recognising that precision in forecasting long-term congestion is unlikely to be high.

2.2a. How does this methodology reflect differences in the output profiles of different generator types?	These differences are very important (see response to Q1.2), and we note that this is not obviously feasible to be reflected in an integer queue number (unless the queue numbers vary by dispatch period?)
2.3. Who should be responsible for administering various aspects of the framework?	No opinion.
2.4. Can queue positions can be traded?	No, as this would encourage speculative securing of queue positions for resale. Rather, there would need to be 'use it or lose it' provisions so that missed development deadlines adjust the queue, relegating the project behind projects originally with higher queue numbers, but which have developed their project more rapidly. In this sense the queue number should be not a firm right until a full commitment to the capacity has been made (i.e. under the AEMO definition of 'Committed'). Otherwise this becomes a sclerosis of the project pipeline as queue-privileged but delayed projects impair the ability of more 'shovel ready' projects to move forward.
2.5. Should energy storage be subject to the same queuing terms as generators?	Consistently with our response to Q1.0 above: it depends on whether the asset is prepared to commit to being restrained from dispatch at time of congestion. If they are, then they should have a queue position of zero.
2.6. Should the framework encourage efficient retirement decisions for end-of-life generators and if so, how?	Yes, it should. How is much more difficult. One answer may be a compulsory auction process for the queue position at a certain project life, where the project itself may bid to retain the queue position. This would reveal whether the access right is worth more to others, presumably a better project which can afford to pay more.
2.7. Should the ESB explore options for new connecting generators to be able to elect to fund additional transmission investment, and receive greater access certainty in return?	No. This sounds like an extremely complicated distraction from the transmission queue model. If proponents believe there is a feasible model for this separate idea, it should be proposed separately. It may well be able to co-exist with any of the status quo, the connection fee model, or the transmission queue model.

2.3 CMM with universal rebates (operational timeframe?)

Locational Marginal Pricing, at the cruder RRP level, has supported investment in the NEM since its inception. This has included choices about which region may offer the best opportunities given regional-level supply and demand, and the constraints of interconnector capacities.

Looked at this way, CMM is evolution, not revolution: just a lower level of granularity in the current market design, with the impact of change at system level entirely cushioned by the universal rebates.

As noted by the ESB (CP, p42) "*Collectively, generators will be better off under the CMM*". So too will consumers be, provided they can rely on effectively competitive markets to share in this improved profitability.

Although CMM is our preferred model, we note well that the detail of rebate allocation is a very important missing piece of the picture for all stakeholders. We expect that as this is clarified, it will become easier to gain support for this model, reflecting the opportunity above.

2.3.1 Support for storage and flexible load is strong

Although characterised as an operational-timeframe model, in our view the very existence of a clear, transparent locational marginal price is in fact a critical element in supporting investment decisions by the types of assets which can relieve congestion – such as storage and flexible load.

Under CMM, such assets will be assured they have the opportunity to deploy their flexibility in ways which lower system costs by relieving congestion when it occurs, and in return, they will face exactly the same certainty all generators see today: a price settled in the gross pool energy market, but with periodically lower costs of energy that accurately reflect the marginal value of a constrained MWh in a constrained location in the network.

2.3.2 Rebate allocation is important for participant stakeholders

From a consumer perspective, any rebate allocation process is likely to deliver benefits, since consumers are more focussed on whole-of-system lower costs, rather than the details of who might be winning or losing compared with the status quo.

Therefore, while this is perhaps a second-order concern for us, it remains in consumers' interests that the rebate allocation design is robust and fair (in the eyes of those impacted directly) for two reasons:

1. This is more likely to lead to broader support for the model; and
2. 'Better' allocation of rebates is likely to have the positive effect of lower investment costs, by managing basis risk[8] in a preferred way for investors.

2.3.3 Status Quo is probably not the ideal objective for rebate allocation

While this would obviously appeal to certain well-placed incumbent assets, the perpetuation of winner-takes-all outcomes seems like a missed opportunity to provide a fairer outcome for the long term, especially if the operation of the CMM reduces instances of winner-takes-all dispatch by reducing race to the floor bidding down to identically priced bids.

2.3.4 Rebate alignment with dispatch outcomes seems like the better model

If rebate allocation was broadly aligned with the outcomes from efficient dispatch, this would appear to be the fairest, most predictable outcome. It would also minimise uncertainty in revenue, by reducing or ideally, eliminating the basis risk between RRP and received price, for the volume actually dispatched.

Such an approach would directly and very simply address certain other design questions, such as the treatment of out-of-merit-order capacity: if not dispatched, no rebate.

[8] We define 'basis risk' here as the dollar difference a generator experiences between receiving RRP x volume dispatched under the type of cost-reflective bidding expected under CMM, and the actual CMM settlement from LMP plus rebate. Ideally, the magnitude of this basis risk would be low, which would indicate relatively few or immaterial winners and losers compared with the ideal outcome. And yes, we are ignoring both MLF, and the volume effects of race-to-the-floor disorderly bidding in status quo dispatch.

We appreciate this requires an inferred economic dispatch process, independent of actual bidding, which would need to be based on each asset's short-run marginal costs (including impact of contract positions) – and this is a not-insignificant challenge which leans against the reasonable objective of simplicity.

We do not think an invasive process to require disclosure of actual costs and contract positions would be warranted at all – but we do not think it is beyond AEMO's capabilities to sensibly observe recent dispatch behaviour to estimate this to within a reasonable band, and for that to be used as the key for an inferred dispatch algorithm.

2.3.5 Contract markets will cope

Particularly under a more sensible rebate allocation design like 'inferred dispatch', generator outcomes will be largely predictable and very close to RRP.

In that case, there seems little reason to be concerned that the contract market (based on contracts for difference relative to the RRP) would be adversely affected.

Market participants selling such contracts already internalise risks associated with the complexity of reality versus RRP, including changes in MLF, and volume risk associated with curtailment, when dealing with consumers and retailers – and so they should, as they are best placed to manage this risk (including by their locational investment decisions).

2.3.6 Consultation Questions on CMM with universal rebates

3.1. What objective should we seek to achieve when selecting a metric to allocate rebates between generators?	We suggest, 'similarity to actual dispatch' (see section 2.3.4 above). Other objectives appear to involve greater basis risk. We acknowledge this requires a carefully-designed method to estimate generator costs without creating an intrusive burden on participants – but we expect this is possible via inferring from recent past dispatch outcomes at various prices.
3.2. Should we remove the "winner takes all" characteristics implicit in the current specification?	This is challenging. Looked at in isolation, it seems appropriate to do so if possible (see section 2.3.3 above), particularly if this outcome of rebate allocation is inconsistent with dispatch outcomes. However, we think it is perhaps more important to align rebate allocation with actual dispatch (see Q3.1 above), and so if the CMM continues to allow for winner-takes-all in certain circumstances (e.g. when cost-reflective bids are still equal), then we suggest the alignment of rebate with dispatch would be more important than seeking to create basis risk in the pursuit of a more theoretically 'fair' rebate allocation.
3.3. What are the consequences of the CMM in terms of bidding incentives?	Our support for this model is based on the ESB's analysis demonstrating that if properly-designed, the incentive is to bid towards short-run marginal cost – because that is broadly what a generator would receive after any reasonably fair rebate allocation. This is fundamental to achieving the benefits to consumers of more efficient dispatch (in place of race-to-the floor bidding to carve up shares of the constrained capacity, or perverse outcomes such as interconnector clamping).
3.4. Should we adapt the model to preclude out of merit order generators from receiving rebates when the RRP is low?	Yes. We support the ESB's preference (CP, p41) of rebate allocation to "*generators who participate in the binding constraint, are available and are in-merit*". As noted in section 2.3.4, this would be achieved by default under a rebate allocation based on 'similarity to actual dispatch'

2.4 Congestion Relief Market (operational timeframe)

The CRM offers something quite different from the CMM: a voluntary opportunity for incumbent assets to establish a sub-market for congestion relief in various areas of the network, at various times.

2.4.1 Concern about locational incentives

The CRM seems more designed to allocate congestion among incumbent generators in a profit-maximising way, against the RRP and their portfolio contract positions[9]. On the face of it, there may be nothing inherently wrong with this, as it may lead to greater efficiency and lower costs, but it is not quite the objective of transmission access reform.

Like the CMM, the CRM is characterised as an operational timeframe model – but it has impacts on locational investment decision-making.

In the CRM's case, these may not be at all consistent with the objective of the reform: ESB notes (CP, p47): "*the CRM could drive inefficient locational decisions. This could occur if generators were to locate in places that worsen congestion, and then focus their business model on selling the associated congestion relief.*"

2.4.2 The uncertainty of a voluntary market cannot offer the broad benefits of the CMM

As a voluntary mechanism, we do not think the CRM would be likely to offer the same benefits as the CMM from the perspective of encouraging efficient new-entrant investment in constrained locations, especially the storage and flexible load assets which should be best-placed to genuinely relieve congestion (by time-shifting energy production or consumption in order to avoid periods of congestion).

A prospective asset of this type, looking to locate behind a constraint faces the uncertainty of whether there will be <u>any</u> bidders in this voluntary market for the congestion relief it can offer. Or, there may be only one bidder – resulting in market power and the inability for that asset to secure energy at anywhere near its actual marginal value.

Under these conditions, independent storage and flexible load investors may reasonably ask whether generators may 'starve them out' once they have committed, perhaps preferring to eventually invest in their own captive battery.

Essentially, there is no guaranteed market for energy at a cost / price that reflects congestion, so **there is no viable merchant business model to support the investment locating in the 'right' place.**

The CRM does not appear to support the necessarily robust investment environment needed to attract storage and flexible load to locate in congested areas of the grid, and realise the ISP's lowest-cost system.

2.4.3 Questionable impact on inefficient dispatch

In assessing the CRM, it seems to us that there is no particular reason to expect it would discourage race-to-the-floor bidding, which represents the failure of the current market design and leads directly to inefficient dispatch. The ESB notes (CP, p47) "*the CRM does not fix the problem of generators "cannibalising" each other's output.*"

Indeed, as a voluntary market, participants may demonstrate their preference for the status quo by failing to volunteer – in which case the CRM would achieve nothing.

2.4.4 Complex, untested and apparently expensive to implement

Unlike CMM and its locational marginal pricing, we are not aware of any energy system with a CRM in successful operation, so it is difficult to judge the level of implementation risk accurately – but it would seem to be quite high. The ESB has raised some fundamental questions about the feasibility of the model, suggesting the CRM concept is reasonably immature compared with CMM.

What we can observe is the CRM would require the creation of a new co-optimised market, which is much more complicated to achieve than simply applying the existing LMPs in the dispatch engine to settlement in the CMM.

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[9] CP p47: "*it seems likely that much of the trade in congestion relief would be between two generators rather than between a generator and a battery (or load).*"

This difference is reflected in an order of magnitude difference in the estimated implementation costs: The ESB notes that through consultation with AEMO, original estimates of a model similar to the CRM are $300 million +/-30%, compared to $10-20 million for the CMM.[10]

Given its voluntary nature (and thus, highly uncertain level of uptake by participants) and the apparent disadvantage in attracting new-entrant investment described above, it seems to us that the CMM would start at a significant disadvantage compared with the benefits from the universal CMM.

CRM would have to demonstrate much stronger benefits (in terms of lower systems costs) than CMM, in order to overcome the higher up-front costs and lower proportional benefits to the extent the voluntary model is not taken up by participants. At this point we cannot see any basis for this.

2.4.5 Consultation Questions on Congestion Relief Market

4.1. What key attributes should the ESB seek to preserve as it works out how the dispatch algorithm should solve in the congestion relief market?	Perhaps the ESB should seek to remove some of the key attributes, such as the voluntary basis which appears to be a critical weakness as noted in section 2.4.2
4.2. What implementation costs are involved - both for AEMO and market participants?	We have no better insight than the estimate referred to above in terms of AEMO's costs. For participants, we expect the costs would also be material (for similar reasons: an entirely new market, not just a tweak to the current gross pool energy market settlement), another disincentive to participation in a voluntary mechanism.
4.3. Should we adapt the model to remove the "winner takes all" characteristics implicit in the current specification?	Yes. Refer to section 2.4.3 – it would seem to be very important that any operational timeframe model removes the problems of the status quo that lead to inefficient dispatch.
4.4. Should we adapt the model to reflect queue position in deciding which parties may sell congestion relief?	No opinion.
4.5. What are the consequences of the congestion relief market in terms of bidding incentives?	Our impression is similar to the ESBs, that the CRM appears likely to suit marginal trading between incumbent generators in limited circumstances (not a genuine broad price signal for congestion, including from storage and flexible load assets). We note it may in fact create a new form of profit-maximising gaming behaviour that would involve perverse incentives to locate in congested areas and seek to profit from abstaining from making it worse.
4.6. Should we adapt the model to preclude peaking generators from selling congestion relief when the RRP is low?	This would seem sensible. The fact that it may be necessary indicates another example of inappropriate incentives created by the CRM design.

[10] CP, Page 46.

Appendix 1. Finncorn's Post-2025 submission on TAR

LMP+FTR offers very material savings to consumers through more efficient dispatch, and more efficient location of new investment in generation capacity relative to the existing and new transmission assets. This is a relatively mature reform proposal, developed carefully, supported by clear cost-benefit analysis[11].

Having said that, we do not think LMP+FTR would be sufficient. There is also a complex problem to be solved in encouraging competitive but efficient investment in generation and transmission, and we don't think a laissez-faire approach based only on LMP+FTR would magically lead to the least-cost generation and transmission system.

As such, we generally support the ISP model of a high-level plan based on REZs. One of the consequences of this is the need to manage the interface between central planning and the competitive market, at a REZ level as well as for the overall NEM system.

However, the P2025 Option Paper focus on REZ transmission and access first, to the exclusion of the overall reform, has only served to highlight the disadvantages of not taking the more general whole-of-system approach. Any attempt to create two systems, or to promote interim solutions, adds the complexity by creating major 'boundary issues' either temporally or geographically.

In particular, creating two transmission access arrangements on either side of a defined REZ is not likely to support efficient, lowest-cost investment within REZs (given the risk of being congested and constrained outside the REZ). But it IS likely to create risks of regulatory arbitrage.

In this sense we applaud the ESB's characterisation of the issues, which recognise this problem. That naturally leads to their implicit support for options which move us as close to the LMP+FTR end-game as possible, while acknowledging the resistance or disinterest of stakeholders to this point.

Some of the proposed approaches in the current menu of possibilities are indeed quite close to the original LMP+FTR model, and so these are the versions which should be strongly supported, as they will make it easiest to extend this concept to the overall network.

The issues around **'who pays'** in the first instance for transmission (within a REZ, or in general) seem far less important to us than whether the arrangements drive the most efficient investments in the first place, and the most efficient dispatch of those assets in real time. Ultimately, whether TUOS is initially paid by generators or retailers, it will find its way to consumers in the long run since revenues will tend to reflect total system costs including a hopefully-competitive return on capital.

Therefore – even taking a long-term interests of consumers viewpoint – we strongly resist the urge to reflexively support 'making generators pay' unless that happens to be the most efficient answer.

Where 'who pays' becomes important is where a generator can pay to secure access, in such a way that their cost of capital is driven down by the reduction of revenue risk from future congestion caused by later entrants – an obvious free-rider problem.

LMP+FTR clearly addresses this problem effectively – whether the FTR are secured periodically via competitive auctions or bought up-front at their expected value to guarantee access for a period (which can also be structured competitively).

A1.1 Efficient development of capacity, load and storage is critical

While much of the debate might focus on the traditional generation and load issues, the issues raised by the ESB regarding efficient location of storage and flexible load relative to VRE capacity are more important in our view.

The scarce asset in the future NEM is not bulk VRE or legacy coal capacity, it is the firming, storage and flexibility needed to ensure VRE output translates to least-cost consumer supply.

The ESB's contention is that it is more efficient to locate storage and flexible load within a REZ, than to

[11] Originally under the banner of the AEMC's Coordination of Generation and Transmission Investment or 'CoGaTI' reform.

fund the incremental transmission needed if they are located elsewhere. There might be some specific exceptions (e.g. assets able to benefit from brownfield development costs and transmission network access, by locating nearby current large-scale generation capacity being withdrawn) but we agree with the premise in general, in the absence of anyone suggesting otherwise as far as we are aware.

VRE is fundamentally low-cost and economic as part of the future system, but the investment case for storage, firming and flexible demand response is less clear-cut at the moment. As a result, transmission and access arrangements for REZs must be carefully designed to ensure the investment signal is accurate.

A1.2 Transmission cost approval and allocation must evolve with the NEM

This is clearly a difficult issue for consumers to assess. While the relatively strict RIT-T process is a tried and tested bulwark against gold-plating, that does not guarantee it remains suitable for the transition of the NEM.

The key case is Marinus Link.

We are not suggesting this project is in the long-term interest of consumers in any particular timeframe. But we are well-aware that under the current RIT-T approach, the costs appear to fall disproportionately on the VIC and TAS regions, compared with benefits which we accept are NEM-wide. In addition, the relatively fast rate of change in the NEM suggests the decision about Marinus Link timing needs to reflect this uncertainty and be flexible to change.

The ESB appears to support a fast-track process which avoids overlap between the ISP and the RIT-T, as well as a reconsideration of the cost allocation for interconnection investment.

> **SUPPORTED IN PRINCIPLE:** The ISP is a fact of life now, and the RIT-T should not be a fallback process to frustrate it. Instead stakeholders must focus on optimising the ISP process – including its assumptions and methodology. Subject to careful further assessment in regard to ‘how’, the RIT-T should be changed to optimally balance costs, benefits, and the parties exposed to each across the system as a whole.
>
> This includes the possibility that some benefits are outside the scope of consumers or market participants – in which case, it is appropriate for jurisdictions to contribute to costs which deliver benefits they value.

A1.3 Actionable ISP project process must recognise consumer risks

The ESB outlines the ‘chicken and egg’ problem between generation commitment and transmission investment – and we agree the P2025 design of the NEM needs to recognise this.

This is essentially a problem of timing mismatch between the investment, and the ramp-up of utilisation of the investment which eventually delivers the benefits to consumers. The problem reflects the uncertainty inherent in the ISP process, which contemplates multiple future scenarios and associated least-cost investment pathways.

However, it is NOT clear to us that the risk associated with making decision under conditions of uncertainty should be shouldered by consumers alone – nor TNSPs, if they are the alternative.[12]

The ESB’s options paper states:

“… if a transmission investment associated with a REZ is classified as an actionable ISP project and passes the RIT-T, it is able to proceed on a regulated basis – that is the assets would be built, owned and operated by the local TNSP and funded by consumers.”

> **NOT SUPPORTED:** This places <u>all</u> risk of poor planning or poor execution with consumers, in a process where they have limited influence. In our view, this is another area where jurisdictions may have a valid role to play in deploying stimulus to the transition. If the ISP determines an asset

[12] The apparent need for the CEFC to step in with a subordinated debt facility to get Project EnergyConnect over the line (following the AEMC’s dismissal of the rule change request to adjust financing arrangements) does suggest there is a significant issue to be addressed here. TNSPs are tightly-restricted in their ability to match (regulated) returns to risk and uncertainty.

needs to be built under conditions of uncertainty, consumers should not be taking the timing risk or utilisation, nor should the risk and associated cost be passed back to TNSPs – but it might well be the role of jurisdictions to bridge the gap. This could be either via short-term financing to TNSPs (as in the recent CEFC facility for Project EnergyConnect) or underwriting regulated asset revenues to the extent they are not justified by asset utilisation in the ramp-up period.

A1.4 Access reforms should move as close to LMP+FTR as possible, now

This is the key reform in this workstream and in our opinion, the most important issue in the entire P2025 portfolio. The ESB's framing of the issue is very clear about the need to get this right.

A1.4.1 Criteria are good but could be better

In assessing options, the ESB has considered four criteria:

1. **Locational signals** for generation and storage (in the investment timeframe)
2. **Congestion management** (price signals in the operational / dispatch timeframe)
3. **Enabling new technologies** (essentially, providing the right signals for storage and flexible loads to locate close to VRE and thus minimise transmission investment and/or congestion)
4. **Risk management tools** (providing a means for market participants to manage the congestion risk to which they are exposed by the signals above)

This is an excellent list as far as it goes, but we believe three other criteria need to be considered:

5. **Consistency with the ISP**
6. **Ease of migration to full LMP+FTR**
7. **Limited reliance on centrally-planned congestion cost estimates**

We describe each of these below.

A1.4.1.1 The ISP assumes LMP-based investment and operational signals

The P2025 and ISP consultation processes revealed to us critical ISP assumptions we had been unaware of.

The ISP is a model which optimises for the least-cost system. In doing so, it assumes generation, storage and transmission assets are located based on optimal investment signals, and that generation and storage dispatch is based on least-cost SRMC bidding.

By contrast, the ESB's analysis of this issue makes it clear the real world – <u>if the access regime is not corrected</u> – involves:

- **Increasing disorderly 'race to the floor'** bidding leading to inefficient dispatch of generation into transmission constraints.
- **Inappropriate generation investment signals** – which reward new entrants locating behind transmission constraints given their ability to access a share of the 'race to the floor' pie.
- **Underutilisation on interconnector capacity** – due to counter-price flows between regions and clamping of interconnector capacity to minimise the unfavourable price impact of this.
- **Perverse signals for storage** (and flexible load) assets – which may charge when they should be discharging and vice-versa, due to the unrecognised impact of local transmission constraints compared with exposure to only the regional reference price.

In short, <u>the ISP assumes investment and operations based on LMP</u>. If that is not correct, the ISP modelling is invalid. There are really only two directions we can go from this point:

1. **Squib on transmission access reform**, and adjust the ISP modelling to reflect the higher costs associated with incorrect price signals; or
2. **Bring the real world into alignment** with the conditions needed to realise the ISP's least-cost system.

In our view, opponents of LMP+FTR are implicitly suggesting we take the first path. This is a dismal outlook for market design and energy policy generally, from the point of view of consumers exposed to the inefficient costs implied by such a failure.

The system is currently sleepwalking into circumstances the ESB and AEMC have clearly alerted us to. Any access reform under the P2025 process should be judged against how well it will push back against this.

A1.4.1.2 The future is LMP+FTR
While we regret the ESB deferring the full-scale debate needed on LMP+FTR, it seems clear to ourselves and the ESB that we must move eventually to an efficient access arrangement based on LMP+FTR.

Therefore, any interim arrangements should be judged on how smoothly they can facilitate that medium-term outcome. This mitigates against partial reforms which might provide some benefits, but are not easy to unwind or fold into a full LMP+FTR reform in (we hope) the foreseeable future.

A1.4.1.3 No need to guess the cost of congestion
One of the ironies of the situation is that LMPs already exist as an integral part of the operational dispatch process – in many ways, LMP is the easy, obvious path to apply an accurate real-time cost to congestion and (by extension) forecast the future cost for the purposes of investment signalling.

However, several of the options proposed involve complex, centrally-administered forecasts of future congestion in order to provide a proxy price signal for investment. At worst, these are imposed as a congestion fee. Slightly better, they are established through competitive processes (such as auctions where the pricing is at least subject to the views of the market participants affected).

The ideal is to apply LMP in the operational timeframe, and use FTR, which would be priced as the expected future value of congestion, as the investment-timeframe locational signal. Any P2025 proposal which falls short of this should be assessed favourably based on how close it can get.

A1.4.3 Hybrid Congestion Management and Connection Fee model is preferred
Five possible models are investigated – of these, three appear to fail immediately:

- **Congestion Management model:** fails to provide the critical locational price signal for investment to minimise congestion / transmission costs.
- **Connection Fee:** fails to provide the operational price signal to eliminate disorderly bidding and to properly incentivise least-cost behaviour by storage and flexible load assets.
- **Generator TUOS:** identical failure to Connection Fee.

However, the Congestion Management model provides a very strong basis for operational price signals to optimise dispatch behaviour by generation, storage and flexible loads – and it does so by applying LMP. In that respect it also meets our extra criteria very well.

As a result, the ESB has evolved the Congestion Management model into two hybrids, combining it with locational price signals. The more extensive of these addresses locational signals adequately, providing:

- **A rebate from congestion impacts for both existing plant and foundational REZ generators**.
  - This is a strong incentive for assets to locate inside a REZ – with the potential for an access auction to recover some of this value for consumers in reduced TUOS.
  - For incumbent assets, they are fully grandfathered against the impact – fair enough given this is a question of forward-looking investment decisions, not revisiting the past.
- **A congestion fee arrangement, to allow new entrant generation capacity** outside a REZ to gain protection from congestion impacts, in return for a fee based on an estimate of those impacts.

'OPTION 5' SUPPORTED: While it isn't ideal, the introduction of LMP to all assets will alleviate a major element of the overall problem, by aligning bidding behaviour with least-cost system assumptions. This will benefit consumers – with AEMC modelling indicating $1bn of NPV over 2026-2040.

In addition, it provides the correct price signals to storage and flexible load. That is likely to be of material value in terms of efficiency if those assets therefore locate close to VRE assets within REZs, and thereby minimise the cost of new transmission required and the quantity of VRE spilled rather than used.

The congestion fee is a somewhat clumsy proxy for the purchase of FTR as a form of firm access, while the rebate to REZ-located generators is a very blunt signal indeed – albeit the value may be discovered and partially recovered by consumers via REZ access auctions.

In our view, this is a viable and significant step towards full LMP+FTR.