ENERGY SECURITY BOARD

Transmission access reform

Consultation paper

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List of Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COGATI	Coordination of Generation and Transmission Investment
CMM	Congestion management model
CRM	Congestion relief model
EOI	Expressions of interest
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
GW	Gigawatt
ISP	Integrated System Plan
LHS	Left hand side
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
PPA	Power purchase agreement
REZ	Renewable Energy Zone
RHS	Right hand side
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
RRP	Regional Reference Price
TNSP	Transmission Network Service Provider
TWh	Terawatt hour
VRE	Variable renewable energy

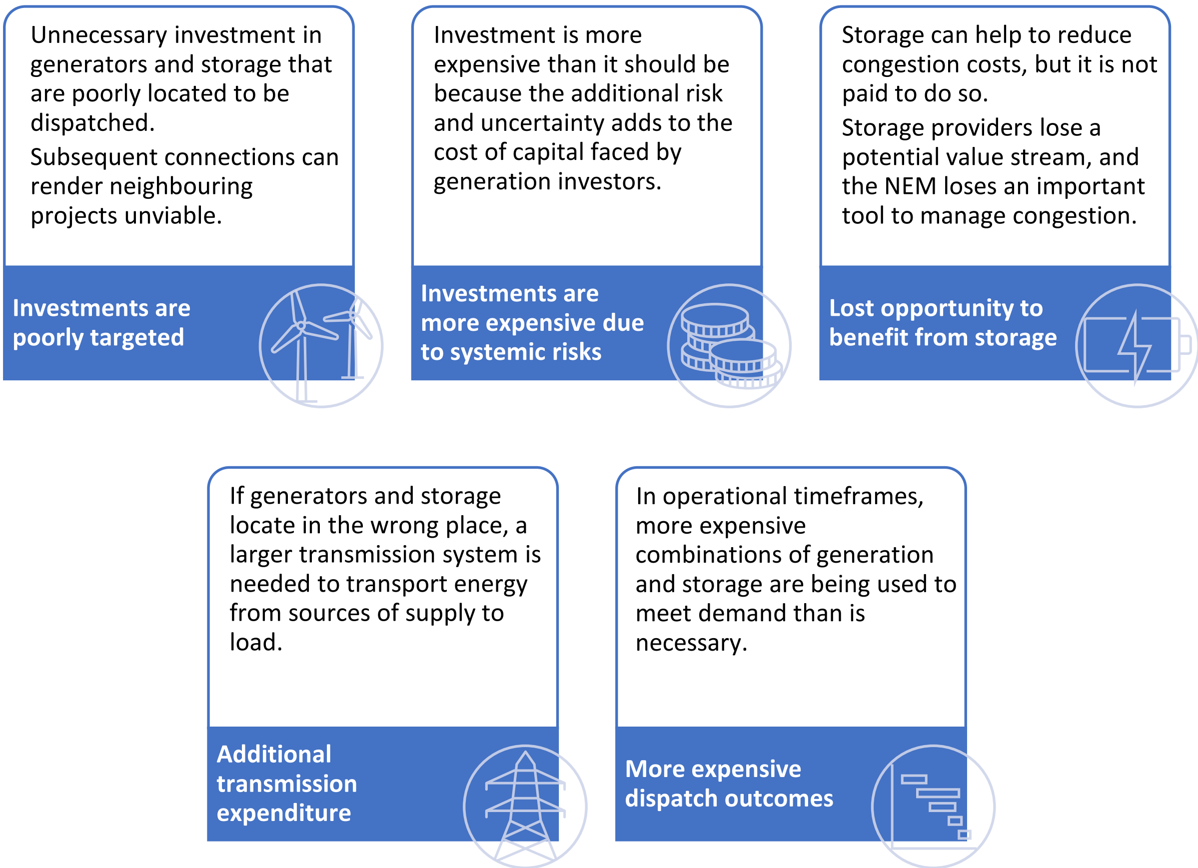
Executive Summary

As the National Electricity Market (NEM) transitions towards higher levels of variable renewable energy (VRE) and flexible resources such as storage and hydrogen, transmission congestion will increase. This is expected despite the significant investment in transmission augmentation. The energy transition can be delivered more cheaply and quickly if new generators and storage connect in places that facilitate the full benefit of all these resources coming into the national power system.

In some cases, generators are connecting in locations where, a lot of the time, they are not adding new renewable energy to the power system. Instead, they are displacing the existing renewable generators. If we don't change the access regime, we are likely to end up with a larger generation and storage fleet and transmission network than necessary to achieve the same decarbonisation and reliability outcomes (see Figure 1).

These issues are being recognised by some State governments who have sought to progress reforms to implement renewable energy zones (REZ) within their regions. The work of the Energy Security Board (ESB) aims to support and dovetail with these initiatives.

Figure 1 Consequences of failing to act on access reform



National Cabinet has instructed the ESB to progress detailed design work on transmission access reform for the NEM and to submit a proposed rule change to Energy Ministers by December 2022. The design process should include a comprehensive consultation process and take into consideration value for money, locational signals and ensuring sufficient flexibility for jurisdictional differences.[1]

1 Refer to Summary of the final reform package and corresponding Energy Security Board, published October 2021

In November 2021, the ESB published a project initiation paper that gave stakeholders the opportunity to submit alternatives to its preferred model at the time, being the congestion management model (CMM) adapted for REZs.[2]

In January 2022, the ESB received 18 submissions, with stakeholders proposing a range of alternate models in various stages of development. Ten model options have been assessed. The ESB has engaged with stakeholders to understand their proposals and identify the best features of the proposed model designs. The models were then assessed against a set of access objectives and assessment criteria that were developed in collaboration with the ESB's Congestion Management Technical Working Group.

The ESB's transmission access objectives relate to two different timeframes – the time when investment decisions are made, and the operation of the power system in real time. We have refined the transmission access objectives to clarify how the objectives map to these timeframes.

Figure 2 Summary of transmission access objectives

Investment timeframes *The level of congestion in the system is consistent with the efficient level.*	Operational timeframes *When congestion occurs, we dispatch the least cost combination of resources that securely meets demand.*
1. Investment efficiency: Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, considering the impact on overall congestion. 2. Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.	3. Operational efficiency: Remove incentives for non-cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.
4. Incentivise congestion relief: Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.	

This categorisation by timeframe also applies to the access models suggested to us by stakeholders, which typically focus on either investment or operational timeframes. It is necessary to develop a solution for each timeframe to meet the transmission access objectives.

Based on stakeholder feedback and our assessment against the access objectives, the ESB has shortlisted four out of the ten models. The operational and investment timeframe models can be mixed and matched. Our comprehensive consultation process has prompted us to remove the REZ adaptation of the CMM from our shortlist. Instead, we will focus on developing a congestion zone/connection fee-based model. We consider this model will avoid the concerns raised by investor stakeholders with the REZ adaptation of the CMM.

2 ESB, Transmission access reform – Project initiation paper, November 2021. Available at: https://www.datocms-assets.com/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf

Table 1 Shortlisted models for detailed design

Investment timeframes	Operational timeframes
Congestion zones with connection fees Investors receive clear up-front signals about which network locations have available hosting capacity.	**CMM with universal rebates** Establishes a single, combined-bid energy and congestion market
Transmission queue Establish a transmission queue that confers priority rights (either to allocate rebates in the CMM or to establish who buys and sells congestion relief in the CRM).	**Congestion relief market (CRM)** Changes to the market and settlements to provide separate revenue streams for energy and congestion relief.

A whole-of-system transmission access solution is a key complementary reform that will support and strengthen State REZ schemes by:

- strengthening incentives for new entrants to locate and participate in REZ investments
- giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investment that locate outside the REZ in the broader shared network
- removing opportunities for subsequent connecting generators to "free-ride" on REZ transmission investments without contributing to them
- promoting the efficient use of REZ transmission infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

It will be important to balance the duration of access rights, which provide revenue certainty for current investments, against the need to incentivise cheaper new entrant technology in the future to promote effective competition in the wholesale market over the long-term.

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. The ESB has been working closely with jurisdictions as it develops this paper, including through its jurisdictional advisory group. We outline in this paper how the various model options could dovetail with REZs.

The purpose of this consultation paper is to seek feedback on the four model options, which will guide the next stage of detailed design. Going forward, the ESB will continue to work with stakeholders to develop these models to a sufficient level of detail to support a recommendation to Ministers. The ESB anticipates that detailed design will be a hybrid model that incorporates one of the investment models and one of the operational models set out in this paper. As part of this work, we will consider the implementation costs associated with the different models. While all models require further design and development, in their current forms, there is a very substantial differential in implementation costs between the operational timeframe models. Being more expensive does not preclude a model from being selected, but the additional costs would need to be offset by commensurately higher benefits relative to the alternative options.

The paper also shares the assessment outcomes of the remaining six models. While they will not progress on a standalone basis, elements of their design features have been incorporated into the shortlisted versions.

Submissions on this paper are due by 10 June 2022.

The ESB will hold a public webinar on 26 May 2022 to assist stakeholders with their submissions.

1 Introduction

1.1 Context

National Cabinet has instructed the ESB to progress detailed design work on transmission access reform and to propose a rule change to Energy Ministers by December 2022. To deliver on this task, the ESB will seek to:

- address the problems that prompted National Cabinet to ask the ESB to conduct the review, namely, the problems associated with the current access regime
- work with stakeholders to understand their concerns and respond to them where appropriate, including by considering alternative mechanisms proposed by stakeholders
- ensure sufficient flexibility for jurisdictional differences.

While the ESB recognises there are critical interdependencies between transmission access and transmission investment, they are distinct, and this review is focused on the former. Transmission investment is being considered as part of the AEMC's Transmission Planning and Investment Review.[3]

The purpose of this consultation paper is to seek feedback on four model options, developed through significant stakeholder consultation, which will guide the design choices during the next stage of detailed design. Going forward, the ESB will continue working with stakeholders to assess and develop a preferred model to recommend to Ministers. The ESB anticipates that detailed design will be a hybrid model that incorporates one of the investment models and one of the operational models set out in this paper.

1.2 Process

The ESB initiated this project by publishing an initiation paper on 26 November 2021. The paper set out the project's objectives, assessment criteria and timeframes. The ESB's priority was to identify new, alternate access reform models. The ESB received 18 submissions with seven alternate models proposed by stakeholders. Several stakeholders developed models in response to the project initiation document. In addition, we were asked to consider several models that were developed in the context of other reviews. In total, ten models have been assessed. Of the ten proposals:

- Four models are shortlisted for further consideration; of which two address objectives in investment timeframes and two in operational timeframes.
- Six models are deprioritised. These models did not satisfy the transmission access reform objectives on a standalone basis. However, some of the design elements of these models merit further consideration and have been incorporated into the shortlisted versions.

The shortlisting is an outcome of extensive stakeholder engagement, including public forums, working groups and industry briefings. In February 2022, the ESB held a virtual seminar to give interested parties the opportunity to understand and discuss the various models proposed by stakeholders as alternatives to the congestion management model. Members of the ESB's Congestion Management Technical Working Group and Jurisdictional Advisory Group have also made significant contributions to our work. Further information on the ESB's stakeholder engagement process is available here.

The ESB is seeking stakeholder feedback regarding the options that will best address the access reform objectives. The process for making a submission is described in Chapter 4.

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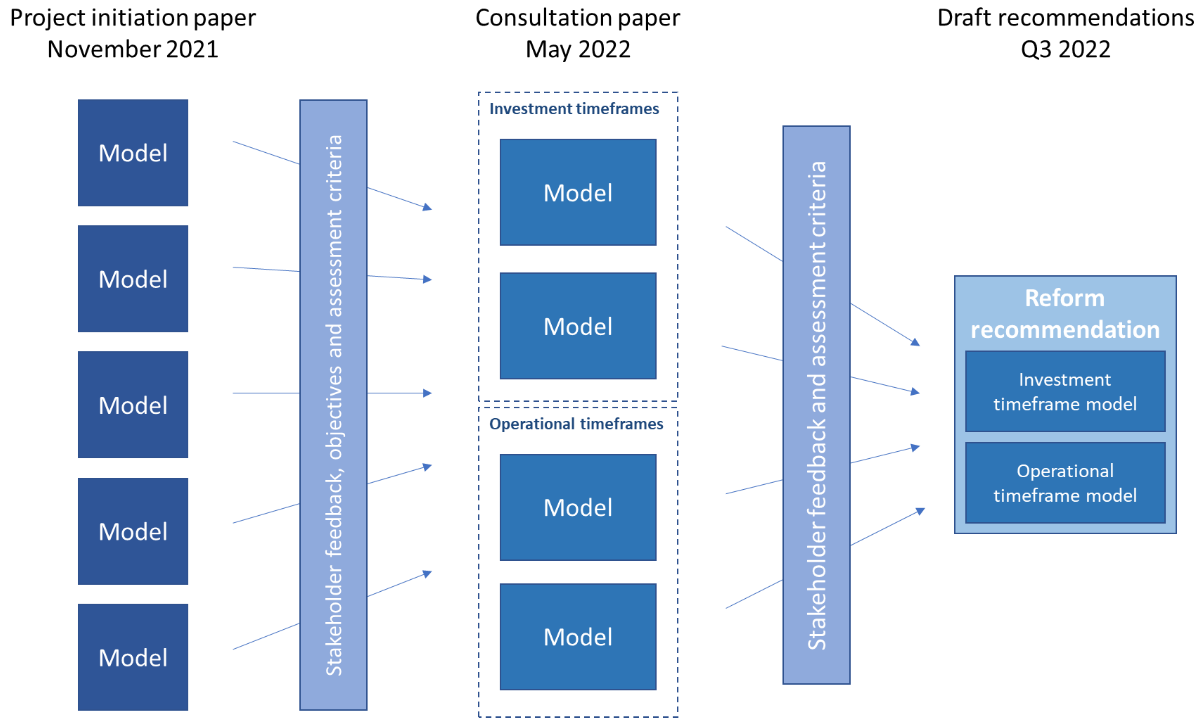
[3] See https://www.aemc.gov.au/market-reviews-advice/transmission-planning-and-investment-review

Over the coming months, we will continue to work with stakeholders to further develop the shortlisted models to gain a better understanding of how they would work in practice, and their strengths and weaknesses. Going forward, this work will enable us to develop and consult on a draft hybrid model that addresses the objectives in both investment and operational timeframes.

Figure 3 Stages of the design process and next steps



Source: ESB

At the end of the next stage, the ESB will select the best performing options for each timeframe in order to develop a single model for the draft recommendation. The ESB considers that each of these models have the potential to improve from the status quo and be in the long-term interest of consumers.

The ESB would like to acknowledge the collaborative response from stakeholders in developing and assessing the model options. Transmission access reform challenges have persisted since the beginning of the NEM and the constructive approach of stakeholders has provided a strong foundation for the ESB to proceed to the next detailed design phase. In particular, we would like to thank working group members and model proponents for their engagement on the challenge of access reform. We wish to continue this collaborative approach to develop the best access reform model to meet the current and future challenges of a transitioning power system.

1.3 Objectives and assessment criteria

The congestion management detailed design process seeks to identify the model/s that best promotes all four of the transmission access reform objectives.

The project initiation paper[4] set out draft objectives and assessment criteria, which provide critical parameters for this workstream. They form the basis of our analysis of alternate congestion management models including our explanation as to which models will (and will not) be progressed beyond this consultation paper. The objectives and assessment criteria have been refined based on feedback from the Congestion Management Technical Working Group.

1.3.1 Access reform objectives

The refined objectives and assessment criteria are set out below. They outline the desired outcomes of the reform. A summary of the stakeholder feedback on the draft version, together with changes since the project initiation paper, can be found here in the Technical Working Group's meeting materials that are published on the ESB website.

The ESB has refined its language to articulate its intent more clearly with respect to Objective 2. The previous phrasing of "increased investor confidence" could be interpreted as needing to restrict future connections (and associated competition or network utilisation benefits) to maintain the access of existing connections. The ESB does not consider this to be the intended objective of transmission access reform, nor is the reform intended to be exclusively investor focused. 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. We are not seeking to protect incumbents from competition, but rather to address limitations with the current market design and enable investors to actively manage risk that arises beyond a naturally competitive market.

We also recognise that the scale of the transition means that significant amounts of new resources need to connect to the system. AEMO's draft Integrated System Plan (ISP) suggests we need 122 gigawatt (GW) of additional variable renewable resources by 2050 in the Step Change scenario. Therefore, we are mindful to avoid making this transition harder than necessary to achieve.

While the first three objectives capture all technologies, the fourth objective explicitly notes 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.

Other refinements include amending language to ensure the objectives are technologically neutral and acknowledging that new generation can contribute other benefits to the system beyond competition benefits, such as system security and reliability.

4 ESB, Transmission access reform – Project initiation paper, November 2021. Available at: https://www.datocms-assets.com/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf

Figure 4 Access reform objectives

Investment timeframes

Goal: Level of congestion in the system is consistent with the efficient level.

1. Investment efficiency (locational signals):

Better long-term signals for generators, storage and scheduled loads to locate in areas with available and proposed transmission capacity – including, but not necessarily limited to, REZs delivered in line with the ISP and state government policies – where they can provide the most benefit to consumers, taking into account the impact on overall congestion.

2. Manage access risk:

Address elements of the current market design that have the effect of amplifying investor risk above what would occur in a natural competitive market. The intent is to achieve a level playing field that balances investor risk 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.

Operational timeframes

Goal: When congestion occurs, we dispatch the least cost combination of resources that securely meets demand.

3. Operational efficiency (dispatch signals):

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

4. Providing the right signals for alleviating congestion:

Establish a framework that incentivises technologies that can help to alleviate congestion (e.g. storage and demand-side resources) to locate where they are needed most and operate in ways that benefit the broader system.

Source: ESB

1.3.2 Assessment criteria

The ESB has also refined the set of criteria on how it will assess the proposed models to move towards a draft recommendation. The criteria draw upon National Cabinet's decision, the four core objectives for transmission access reform, and the ESB's statutory duty to make recommendations that are consistent with the national electricity objective (NEO).[5]

The refined assessment criteria are set out in Table 2. We recognise that the assessment criteria cannot all be perfectly met but must be traded off to achieve a balance that best promotes the long-term interests of consumers. A model that strongly meets an individual criterion may score lower on others. The criteria will not be treated as a box ticking exercise but rather as a balancing act to select the most suitable model and the best detailed design features within the model, for example, comparing the costs of implementation with the expected benefits to be achieved.

Table 2 Access reform assessment criteria

	Criteria	Description
1	Efficient market outcomes – investment	• Better incentives for generators, storage such as batteries, and load such as hydrogen electrolysers to locate in efficient areas. In the case of generation, this is most likely where there are low congestion levels, such that transmission assets are better utilised. In the case of storage and load, these may be congested areas to help alleviate that congestion and use otherwise wasted renewable electricity that could not reach the load.
2	Efficient market outcomes - dispatch	• Better incentives for generation, storage such as batteries, and load such as hydrogen electrolysers to bid in a fashion that best reflects its underlying costs, resulting in more efficient dispatch outcomes and reducing fuel costs across the NEM. In turn, this may also reduce emissions.
3	Appropriate allocation of risk	• Risk arising due to congestion in the NEM should be allocated, to the extent possible, to the party that is best placed to manage or otherwise bear that risk, noting the practical limitations on exposing parties to risk without appropriate mitigation tools and measures.
4	Manage access risk	• Lower risk to investors, where the benefits of doing this outweigh the costs (from a consumer perspective), by addressing the features of the current market design that amplify access risk. • Facilitate market participants' ability to manage access risk. • Managing the risk arising from regulatory change, i.e. consider whether there are strategies to mitigate the impact of the changes on market participants.
5	Effective wholesale competition	• Any changes should promote an effectively competitive wholesale market by avoiding creating barriers to new entry; any additional costs to new entrants associated with their transmission connection reflects a benefit(s) they receive in return.
6	Implementation considerations	• Cost and complexity: cost and complexity of implementation, including the impact of the system's physical complexities and ongoing regulatory and administrative costs to all market participants, consumers and market bodies, compared to the expected benefits of the option, and as compared to the status quo. • Timing and uncertainty: uncertainty of outcome, the likely timing of benefits versus costs.
7	Integration with jurisdictional REZ schemes	• As requested by Ministers, the proposed rules must provide flexibility such that differences between jurisdictions' access schemes, including those without REZ schemes, can be appropriately integrated.

5 Section 90F(4)(b) mandates that for South Australian Minister made Rules on recommendation from the ESB the ESB must is satisfied that the Rules are consistent with the national electricity objective (NEO).

Criteria 3, 4 and 5 reflect the balancing interests of different parties (consumers, investors/incumbents and new technology providers). We deemed it necessary to separate these criteria to ensure that each is fully considered. Some models re-allocate risks but may not facilitate management of those risks e.g. models that transfer risk from market participants to customers. Alternatively, a model may enable investors to manage their risk, but in a way that creates barriers to new entry. This is a key trade-off when designing the models – that is, the appropriate balance between investors' ability to manage risk and promoting effective wholesale competition over the long-term – with the overall goal being the long-term interest of consumers, consistent with the NEO.

2 Case for change

To understand the nature of the congestion challenge we need to understand:

- that congestion is an inherent feature of a high VRE power system, and hence, we need to be able to manage it well
- how we currently manage congestion
- how these arrangements lead market participants to make decisions that are individually profitable but lead to inefficient outcomes for the broader system
- why access reform is required to support jurisdictional REZ schemes.

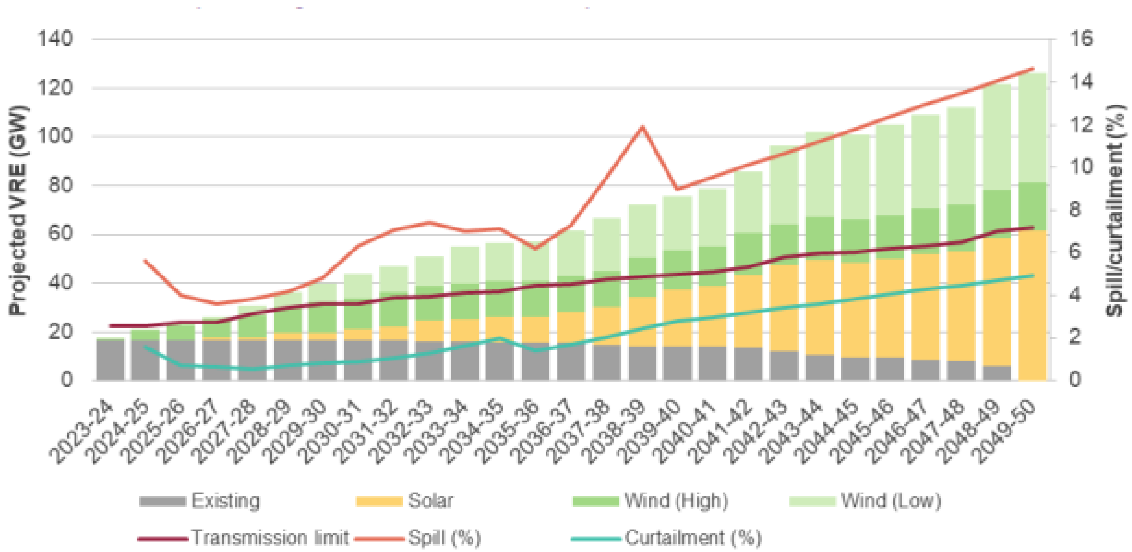
This chapter outlines these issues and discusses the consequences for customers if we fail to reform.

2.1 Congestion will be more common in the future

Congestion is a normal, everyday feature of efficiently sized transmission infrastructure to accommodate VRE. It is not an anomaly. It can be profitable for solar developers to build solar farms that produce surplus output during the middle of the day, so that they can produce more during the lucrative shoulder periods. It would be inefficient for the transmission network to be able to accommodate all this surplus generation.

AEMO's 2022 draft ISP forecasts that congestion will continue to increase even after the actionable ISP projects are built. The ISP does not, and should not, seek to remove all congestion from the system. Doing so would impose substantial costs on consumers. Issues relating to access will be common despite the transmission infrastructure expansions foreshadowed by the ISP. The draft ISP projects a need for 63 GW of transmission network capacity to accommodate approximately 127 GW of utility-scale VRE by 2050 i.e. transmission capacity is less than half of utility-scale VRE capacity.

Figure 5 Projected utility-scale VRE in REZ for the NEM, the transmission network capacity to facilitate this development together with the economic spill and transmission curtailment[6]



Note: Curtailment and economic spill are interpolated between 2039-40 and 2048-49. The transmission limit does not include upgrades required to alleviate group constraints.

6 AEMO, Appendix 3 Renewable Energy Zones Draft 2022 ISP for the National Electricity Market, December 2021, p. 11.

It should be noted that the lost output due to transmission curtailment and spill in the chart above is cumulative i.e. in 2050, approximately 5 per cent of output is lost due to transmission curtailment in addition to approximately 15 per cent of output that AEMO expects to see voluntarily switched off for economic reasons.

The level of congestion forecast in the ISP is likely to understate true levels for a number of reasons. First, the modelling is focussed on congestion occurring during system normal conditions. The complexity of the modelling task means that it is not feasible to include network outages. However, historical experience suggests that a significant proportion of congestion arises because of network outages. For instance, in 2020, 41 per cent of non-FCAS (frequency control ancillary services) binding constraint hours in the NEM were attributable to network outages.[7]

Second, 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.

2.2 Current arrangements for managing congestion

The ESB's recent stakeholder engagement process has highlighted the critical role of generator coefficients in determining how transmission access is allocated between market participants in the presence of congestion. We had cause to reflect on this issue when we received the alternative options that relied on changes to the tie-breaker rules to give effect to access rights. While tie-breaker rules are relevant, insofar as they explain why market participants engage in "race to the floor" bidding, they rarely drive dispatch outcomes in practice.

Instead, generator coefficients tend to determine who gets dispatched in the presence of congestion. In previous documents, the ESB used simplified examples that did not reflect the role of coefficients. To remedy this, this section describes how congestion is managed under the current market design, including the role of generator coefficients and the associated winner takes all outcomes. Section 2.3 discusses the consequences of these arrangements.

The NEM has a transmission access regime whereby parties may connect to the grid at any point (subject to meeting technical requirements) and fund only the cost of the assets required to connect to the shared grid. Generators are not required to contribute towards the cost of the shared transmission network, and they receive no assurance that the transmission network will be capable of transporting their output to load centres.

In operational timeframes, the volume that a generator may dispatch into the market is determined via the NEM's dispatch engine (NEMDE). NEMDE is a security constrained co-optimised dispatch algorithm that determines the output of each generator and the level of congestion on the network that leads to the overall lowest cost dispatch of generators (as reflected via generators' bids) to meet demand.

NEMDE's objective is to meet demand whilst maintaining system security and avoiding violations of constraint equations. These constraint equations represent the physical limits of the system. Within these requirements, NEMDE attempts to find the least cost way of dispatching generation out of the options available.

7 AEMO, Annual NEM constraint report 2020 Summary data. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams

The left-hand side (LHS) of constraint equations contains all the inputs that can be varied by NEMDE to avoid violating the constraint, such as output from scheduled and semi-scheduled generators and flows on interconnectors. The right-hand side (RHS) of constraint equations represents the physical limit of the system or piece of equipment to which the constraint equation relates. This is determined in advance by AEMO for each constraint equation.

Each generator or interconnector on the LHS of a constraint has a coefficient (also known as a contribution factor, shift factor or participation factor), which reflects the impact it has on the constrained transmission line. The coefficient measures the impact to the constrained line from a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector).[8] The coefficient represents the proportion of the generator's output which "uses" the equipment to which the constraint relates. Typically, the further away a generator or interconnector is located from the constrained line the less it uses of that line, and so the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.

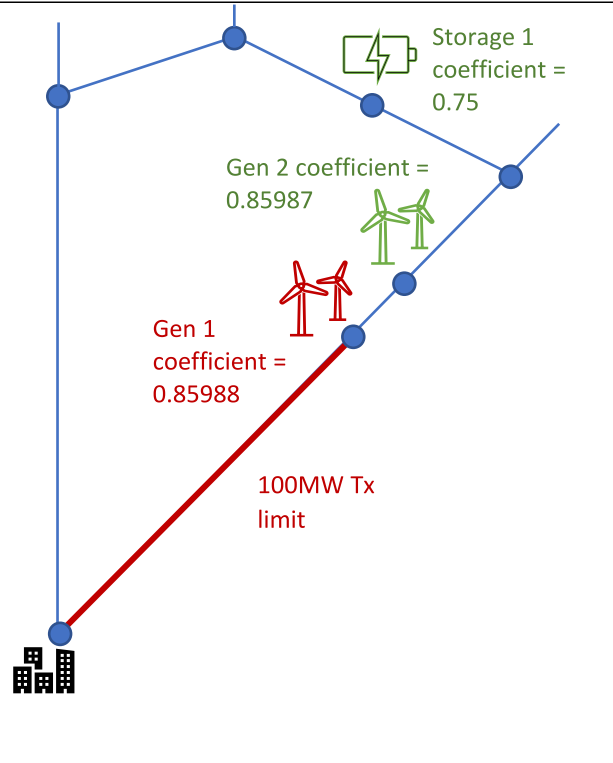
Coefficients are highly granular and hence it is normal for each generator in a constraint to have a unique coefficient. This reflects the physics of the way electricity flows across a meshed network. If there are several generators that could be 'constrained off', NEMDE will choose the lowest cost combination taking into account the prices offered and the coefficients. In circumstances where competing generators all offer the same price (for instance, because generators have bid the market floor price), coefficients become determinative. NEMDE minimises the amount of energy lost due to congestion by dispatching generators with the lowest coefficients first.

This feature of dispatching tied bids based on generator coefficient gives rise to "winner takes all" outcomes. The winners and losers associated with generator coefficients vary over time, as generators enter and exit the market, and demand patterns change, and AEMO's constraint equations change to reflect these events.

Figure 6 shows how if a generator locates in a congested location – but with a lower generator coefficient than their neighbours for relevant constraints – then, other things being equal, they will be dispatched ahead of their neighbours when congestion occurs.

8 For example, if a one MW reduction in output of a generator decreases flow on the constrained line by one MW, the coefficient is +1. A positive coefficient means that a generator may be 'constrained-off' when the constraint binds, while a negative coefficient means a generator is 'constrained-on'.

Figure 6 Illustrative example of "winner takes all" outcomes in the NEM dispatch



Consider 3 market participants, each with availability of 50 MW, that are subject to a transmission limit of 100MW.

If all constrained parties bid at the market floor price -$1000/MWh, NEMDE will maximise the output of low as-bid cost generation by dispatching the market participants that contribute least to the constraint, even if the coefficients are virtually identical. The constraint equation would be:

0.85988 x G1 + 0.85987 x G2 + 0.75 x S1 <= 100

This results in a dispatch as follows, assuming -$1000 MWh bidding:

- 22.69 MW x G1
- 50 MW x G2
- 50 MW x S1.

Generator 1 is curtailed despite having a negligible difference in contribution factor compared to Generator 2.

Source: ESB

The constraint formulation that determines generator coefficients is designed to reflect the physical realities of the power system. As such, this approach gives rise to efficient dispatch outcomes, providing that generators are incentivised to bid in a manner reflecting their costs. The ESB does not propose to change the role of generator coefficients in dispatch. Alternative approaches would have the result that NEMDE dispatches (and customers pay for) more energy than is necessary, with the additional MW unable to reach load due to congestion.

However, given these winner takes all outcomes, change is required to the way that these technical parameters flow through to the revenue received by market participants. Incumbents cannot change their location to optimise their contribution factor, but prospective projects can. But once prospective projects have decided where to locate, newer prospective projects can come along and result in a different outcome. This extreme version of open access makes investing in the NEM riskier than other comparable markets.

In other major electricity markets, generators either pay to access the transmission network, or receive a price for their output that reflects the cost of congestion at their location. These features influence investor decisions by making it less profitable to connect in parts of the network that are already full.

2.3 Consequences of current arrangements for managing congestion

The energy transition can be delivered more cheaply and quickly if new generators connect in places that facilitate the full benefit of all the renewables and batteries coming into the national power system. In some cases, generators are connecting in locations where, a lot of the time, they are not adding new renewable energy to the power system. Instead, they are displacing the renewable generators that were already there. Customers face higher overall system costs for reasons summarised in Figure 7.

Figure 7 Consequences of failing to act on access reform

Unnecessary investment in generators and storage that are poorly located to be dispatched.

Subsequent connections can render neighbouring projects unviable.

Investments are poorly targeted

Investment is more expensive than it should be because the additional risk and uncertainty adds to the cost of capital faced by generation investors.

Investments are more expensive due to systemic risks

Storage can help to reduce congestion costs, but it is not paid to do so.

Storage providers lose a potential value stream, and the NEM loses an important tool to manage congestion.

Lost opportunity to benefit from storage

If generators and storage locate in the wrong place, a larger transmission system is needed to transport energy from sources of supply to load.

Additional transmission expenditure

In operational timeframes, more expensive combinations of generation and storage are being used to meet demand than is necessary.

More expensive dispatch outcomes

As a result of these factors, we end up with a larger generation fleet and transmission network than necessary to achieve the same decarbonisation and reliability outcomes. This section explains how the current access regime:

- increases the level of risk faced by generation investors
- limits opportunities for storage to take on roles that we need to deliver the energy transition, such as firming renewables and offsetting the need for transmission investment
- creates a need for a bigger transmission network than would be necessary if investment in transmission, generation and storage was co-ordinated.

2.3.1 Generation investment is riskier than it needs to be

The current NEM access regime has features that are attractive to generators. It gives them flexibility to connect where they want, and they do not need to pay to access the shared network. Further, the regional price is determined at a specific location which typically has high prices compared to other locations within the region (i.e. the regional reference node (RRN)), meaning that those generators that are dispatched typically enjoy relatively high prices.

However, these arrangements are unstable because they make simplifications which ignore the physics of the system and instead assume – for the purpose of pricing – that the effects of congestion are identical everywhere in a region. More recently, as congestion has increased, the downsides arising from the simplification have become more apparent. An investment boom in renewable energy has meant that new generation investment exceeds the capacity of the transmission network to host it, and as a result some generators are experiencing unexpected curtailment.

Under the current market design, the costs of congestion are not spread evenly between market participants. New investment can be profitable in congested locations, so long as the new entrant skilfully chooses a location that allows their output to take precedence over their neighbours. Congestion is managed via intricate technical criteria rather than more visible signals such as price.

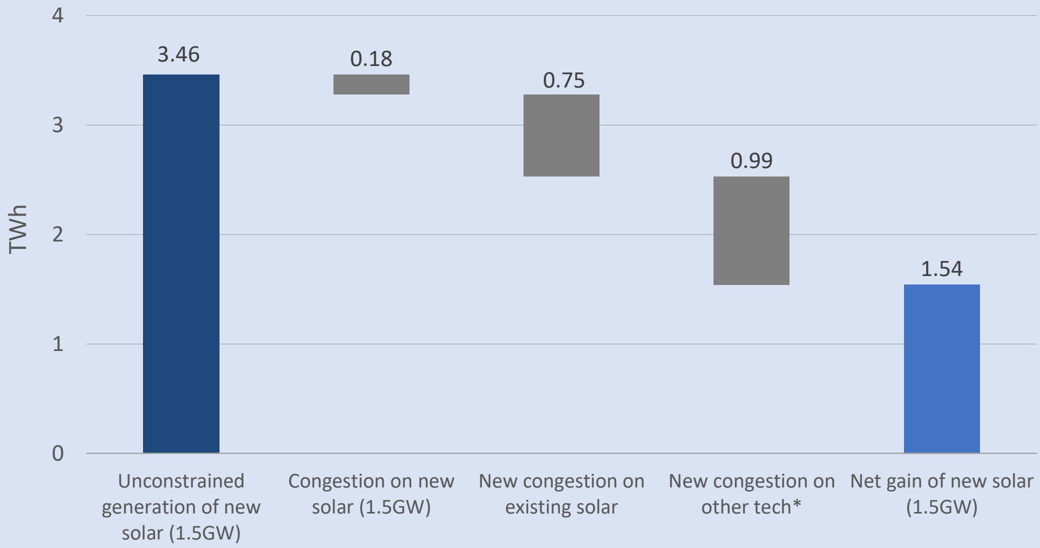
While these features play to the strengths of certain sophisticated investors, they are not good for the efficiency or competitiveness of the NEM compared to other investment opportunities.

Box 1 Impact of additional solar generation capacity on congestion volumes

The modelling below stress tests the impact of generation investment in excess of the levels forecast in the ISP. FTI Consulting (FTI) modelled the impact of adding solar capacity to assess how much that would increase congestion rather than provide net additional capacity to the system. For the test, FTI added 300 MW of additional solar generation to the most productive area in each region (1.5 GW additional capacity in total) for the year 2030. All other inputs and assumptions were derived from the ISP step change scenario assuming no additional major transmission capacity.

The additional solar generation is forecast to generate 3.46 TWh but increases congestion by 1.92 TWh i.e. less than half of the additional energy is a net gain to the system. While the parties investing in additional generation suffered some curtailment, most of the congestion impact was borne by third parties i.e. existing generators. This means that an investment can be privately profitable while not being efficient for the broader power system.

Impact of additional solar generation capacity on congestion volumes



Source: FTI Consulting

** This may be an efficient outcome if the new solar is displacing other tech that has a higher marginal cost.*

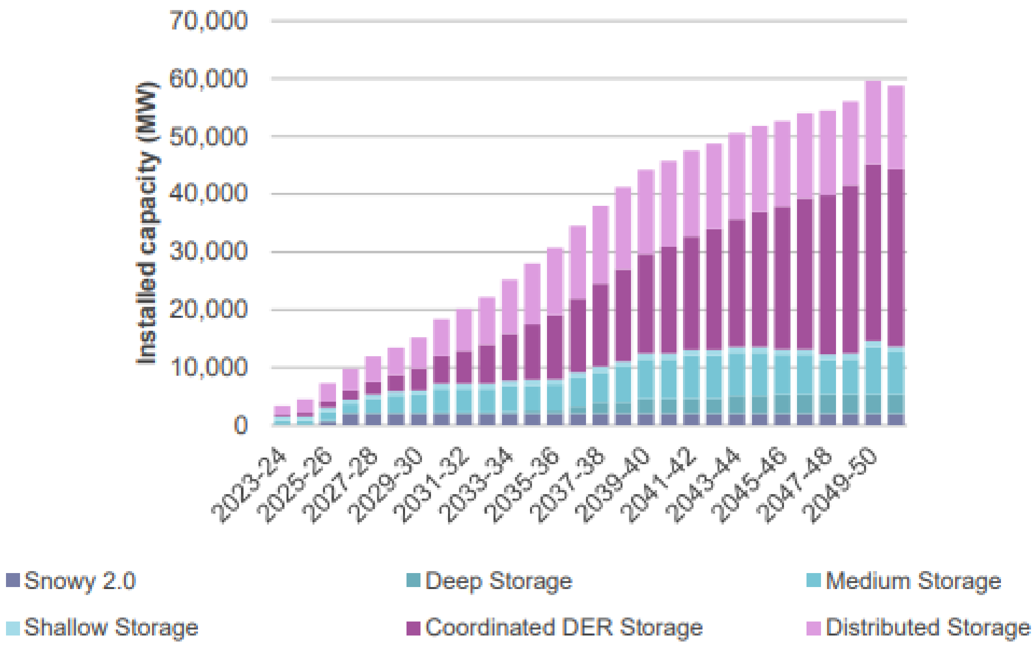
When generation and transmission investment are not coordinated, much of the additional output of the extra generation is offset by additional congestion i.e. a reduction in the output of an existing generator. Further, only a small fraction of the additional congestion is borne by the party that caused it, with the remainder being borne by pre-existing generators. This inefficient congestion affects the profitability of existing generators and has the potential to result in disorderly market exit.

Investors have expressed concern about the uncertainty they face when seeking to connect in the NEM. In an interconnected power system, each connection affects everyone else. Analysis undertaken for the Clean Energy Investor Group suggests that the cost of capital for clean energy projects in Australia is around 100-250 basis points higher than other markets due to significant uncertainty and risk.[9] The only way to provide more certainty to investors on matters such as congestion and constraints is to adopt a more coordinated approach for generators' access and use of the network.

2.3.2 Storage and demand side resources are not paid to provide needed services

Under AEMO's 2022 Draft ISP, substantial new investment in utility scale storage is required.

Figure 8 NEM storage MW capacity in the least-cost development path under Step Change scenario



Source: AEMO Draft 2022 Integrated System Plan, Appendix 2

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 congestion.

The right NEM-wide transmission access regime will help us to stay ahead of, and facilitate the efficient investment in, the expected dramatic increase in large-scale battery deployment and emerging technologies such as hydrogen. As a large flexible load, grid connected hydrogen electrolysers could be a future source of demand response, which can help make the system stable. These technologies need incentives so to operate at times that align with the needs of the power system. That way they work within, and not against, a high VRE power system. Investors should have the opportunity to be rewarded for leveraging the flexibility of these technologies.

Batteries in the NEM have forecast a higher proportion of FCAS market revenues in the early years of investment. With FCAS revenues being relatively small to date and likely to reach saturation with further battery entry, it likely that energy arbitrage will become a more crucial component for business cases in future.

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9 Clean Energy Investor Group, Investor Principles - Unlocking low-cost capital for clean energy investment, August 2021, p. 3. Available at: https://ceig.org.au/wp-content/uploads/2021/08/CEIG_Clean-Energy-Investor-Principles.pdf

The current market design does not reward batteries for alleviating congestion. Instead, batteries are incentivised to behave like a generator, even though they have a broader range of capabilities. Exposing market participants to the marginal cost of congestion could enable batteries to compete with both generation and transmission. For instance, it could promote batteries to become virtual transmission lines that earn revenue by charging up to alleviate congestion, and paid a price reflecting that marginal cost, before discharging when the congestion is finished. The current model design does not reward batteries for alleviating congestion in this way. Due to intra-regional congestion, there are locations (nodes) on the network where this congestion is material. Consequently, storage providers are missing out on a significant revenue stream, and consumers are missing out on an opportunity to efficiently reduce congestion costs.

Table 3 Summary of average intra-day price spreads by NEM region

Region	Average Price Spread RRN	Average Price Spread at location with highest marginal cost of congestion	Difference between High and RRP
NSW	102	280	178
QLD	91	91	0
SA	223	274	51
TAS	106	170	64
VIC	207	274	67

Source: ESB using the AEMO MMS database, 2019

By definition, the location with the highest marginal cost of congestion provides the greatest value of congestion relief when charging (perhaps when sited next to wind or solar farms away from a load centre) and discharging when demand is high and lines are relatively congestion free (perhaps in the evening peak when the sun has set). The uniform application of the RRP removes the opportunity for storage providers to target their investments to network locations with the highest intra-day spread.

The inability to access these prices means that batteries:

- are not able to capture the full value they can provide to the power system and are therefore under-incentivised to enter the market in aggregate
- do not receive efficient price signals to locate at nodes where they can provide the most value to the power system. Given storage's inherent locational flexibility, this is likely to result in significant inefficiency in the medium to long term.

The current design also does not provide efficient operational incentives for batteries. In operational timeframes, the current wholesale pricing framework can give rise to inefficient and complicated results in the presence of congestion. This is because the regional pricing model does not reflect what happens on the power system during periods of congestion. Instead, during periods of congestion the dispatch algorithm applies heuristics that reward market participants for acting in a manner that is inconsistent with economic efficiency.

One such inefficiency is known as 'race to the floor bidding' where generators bid to the market price floor in an attempt to maximise their dispatched output. If the regional price is high, a battery behind a constraint may bid so that it discharges, even if this means that more low-cost generation is constrained off.

Some stakeholders have argued that if all market participants affected by a constraint have the same marginal cost (for instance, VRE generators), then the inefficiencies arising from race to the floor bidding are small. This is true. However, even in a wholly VRE power system, there will always be a need for some form of dispatchable plant to manage intermittency. In particular, the current market design may reward storage for making congestion worse.

This is because they receive the same price in their region, regardless of local congestion. If there is high local congestion, there would be system-wide benefits for the battery to charge. However, if the RRP is high at this time, then the battery will not have the appropriate incentive to do so. Conversely, if there is little congestion in its area, the current incentives do not encourage battery exports. This reduces the value that batteries can offer to the system, particularly where they are needed to support flexible resources. Similar logic and rationale would also apply to locationally sensitive loads, such as hydrogen electrolysers.

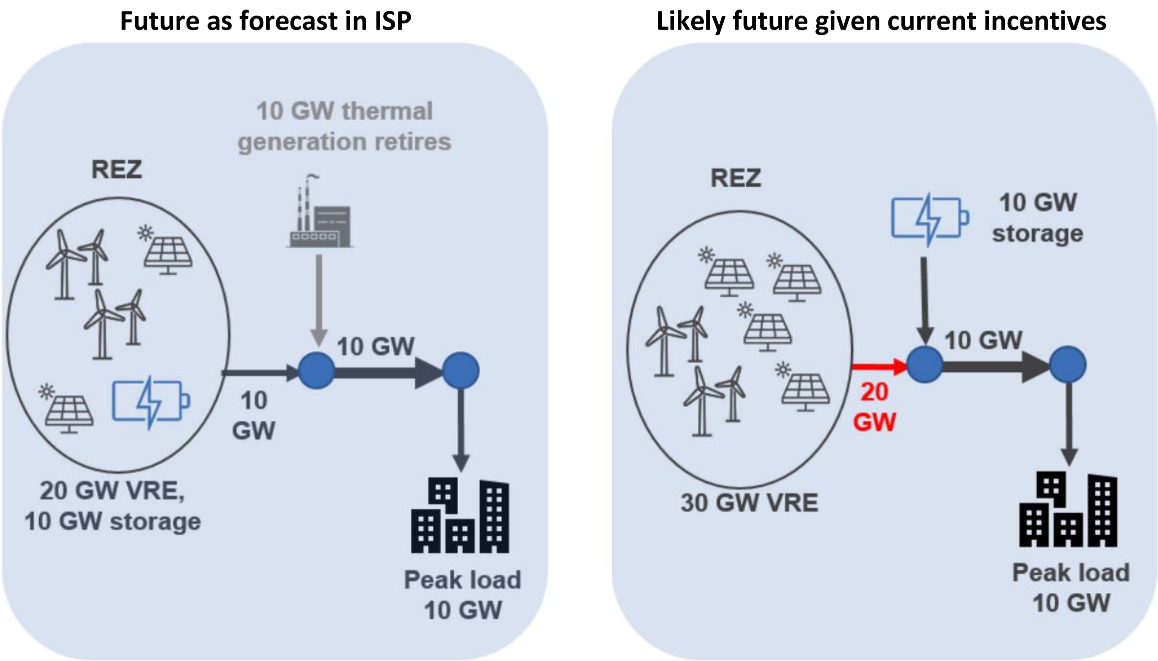
2.3.3 We need to build a bigger transmission network than we otherwise would

The ISP is an engineering assessment that determines the least cost combination of network and supply side resources to meet forecast demand within the parameters of government policy. It is used to trigger transmission investment, but we rely on the market to deliver generation investment. As our current market design is sending the wrong signals, the least cost outcome envisaged in the ISP is unlikely to eventuate.

In particular, the current market design treats batteries as if they were generators and does not reward them for the role that they could play in alleviating congestion. Consequently, it makes commercial sense to build batteries in locations where there is plenty of spare transmission capacity – for instance on the sites of retiring thermal generators.

However, under this system configuration, surplus power generated during windy or sunny periods needs to flow through the transmission system to reach batteries for storage. A better solution is to locate batteries in the REZs because less transmission would be needed to deliver the same level of reliability and decarbonisation.

Figure 9 Impact of current access arrangements on location decisions and transmission investment



If the battery locates within the REZ, during period of high renewables output, 10 MW can flow through the transmission system to supply load, and the surplus of 10 MW can be stored in the battery for later use. If the battery is not co-located with the VRE, then all 20 MW of VRE output needs to flow through the transmission network before it can be stored. In this case, a larger transmission system is needed to meet demand.

Generators typically need to locate where its energy source (e.g. wind, sun, water, gas or coal) is readily available. In contrast, batteries have flexibility in their choice of location. Given its potential to offset the need for transmission investment, the ESB regards efficient signals for storage as a key objective for transmission access reform.

There is also potential for poorly located generation to drive higher transmission costs. This happens when poorly located generation "flips" the cost benefit analysis in the ISP and the regulatory investment test for transmission (RIT-T).

Most of the time, the location of the transmission network drives the location of generation investment. However, ad hoc generation developments can trigger major transmission investments because, once an investment has occurred, the transmission planning process treats its capital cost as sunk. This means that the analysis ignores capital costs associated with generation projects that are already built (since the money has already been spent). In contrast, the cost benefit analysis includes the capital costs of uncommitted projects.

The presence of poorly located committed generation can "flip" the RIT-T to trigger a previously uneconomic investment if the upgrade enables low-cost generation to displace higher-cost generation. Customers may be required to bear unnecessary costs for additional transmission expenditure that would not have been needed if the poorly located generators had located elsewhere.

In other circumstances, the regulatory framework may determine that the costs of alleviating congestion exceed the benefits. If the poorly located generation:

- has broadly the same costs as the generation that it is displacing, and
- is not required to meet reliability standard

then the transmission upgrade required to alleviate congestion is unlikely pass the RIT-T. The constrained generation assets will be stranded until the transmission upgrade forms part of the suite of investments required to meet customer demand at least cost.

Both outcomes are sub-optimal relative to arrangements that enable generation and transmission to develop in a coordinated fashion.

2.4 Role of access reform in supporting REZs

The current access regime is incompatible with REZs because it is not possible to give REZ generators meaningful long-term assurances that they will be able to dispatch their output. Generators are incentivised to become free-riders and connect outside the REZ without having to participate in a tender process. A whole-of-system transmission access solution will support and strengthen State REZ schemes by:

- strengthening incentives for new entrants to locate and participate in REZ investments
- giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investment that locate outside the REZ in the broader shared network
- removing opportunities for subsequent connecting generators to "free-ride" on REZ transmission investments without contributing to them
- promoting the efficient use of REZ transmission infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

It will be important to balance the duration of access rights, which provide revenue certainty for current investments, against the need to incentivise new entrant cheaper technology in the future to promote effective competition in the wholesale market over the long-term.

In the medium to long term, the NEM's version of open access is incompatible with REZs because the problems described in this chapter make it an unstable foundation for co-ordinated system development.

Box 2 Integrating State-based REZ access schemes with a NEM-wide scheme

Several State governments are considering access models that apply a physical access control mechanism to shared transmission assets within the REZ. The ESB agrees that this approach makes sense as an interim measure in localised parts of the network. The ESB's interim REZ principles stipulate that any REZ-specific access model should be simple to implement and administer, with a view to being able to integrate with more comprehensive national arrangements if and when they are implemented.[10] Each of the models under consideration are capable of being applied in conjunction with jurisdictional schemes.

The ESB's final recommendations for the interim REZ framework notes that, ideally, any REZ-specific access scheme would be designed to be superseded by a NEM-wide access model.[11] However, we also recognised that given timing issues, this may not be feasible for certain REZs, such as Central West Orana REZ. REZ-specific access scheme can be designed to prevail within the REZ for the duration of the scheme. The NEM-wide access regime would be used to resolve the risk of access degradation for REZ generators arising due to subsequent connections outside the REZ.

Subsequent chapters set out the ESB's preliminary thinking on how the various access models could be designed to support REZs.

10 ESB, Interim Framework for Renewable Energy Zones Final recommendations, June 2021. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1631503418-esb-decision-document-renewable-energy-zones-recommendations-final-1-june-2021-to-encrc.pdf

11 As above, p. 31.

3 Shortlisted models

3.1 Overview of model options

The ESB has considered ten model options in collaboration with stakeholders. The models have been classified into those that meet the access objectives in operational timeframes and investment timeframes – with some models being split into their investment and operational components.

Table 4 Summary of model options

	Investment timeframes	Operational timeframes
Shortlisted options	Congestion zones with connection fees	CMM with universal rebates[12]
	Transmission queue	Congestion relief market (CRM)
Alternate model options (not being progressed) – Appendices	*CMM – REZ adaptation*	*Revised tie breaker rules*
	Physical access rights via locational connection fees	*Dual price floors*
	REZ cost allocations model	*Fixed shape time of day MLFs*

The ESB worked with stakeholders to identify the strengths and challenges associated with the various models. Feedback processes included written submissions, the virtual seminar, the Congestion Management Technical Working Group, the Post 2025 Advisory Group and the Jurisdictional Advisory Group. Based on the feedback and our assessment against the access objectives, the ESB has shortlisted four out of the ten models.

Table 5 Shortlisted models for detailed design

Investment timeframes	Operational timeframes
Congestion zones with connection fees Investors receive clear up-front signals about which network locations have available hosting capacity.	**CMM with universal rebates** Single, combined-bid energy and congestion market
Transmission queue Establish a transmission queue that confers priority rights (either to be allocated rebates in the CMM or to establish who buys and sells congestion relief in the CRM).	**Congestion relief market (CRM)** Changes to the market and settlements to provide separate revenue streams for energy and congestion relief

The shortlisted operational and investment timeframe models can be mixed and matched. We also consider that these models can all interface with and support REZs that are being progressed by jurisdictions.

The appendices provide the outline and assessment of the six additional models that will not be progressed as standalone options. It is worth emphasising that while the CMM with REZ adaptions is not being progressed, it does not mean that we are no longer considering how these fit with REZs. We consider that each of the above models can support jurisdictional reforms on REZs and have a focus on making sure this can be achieved as we continue to work up these options.

12 Previously “vanilla CMM”.

It is also worth noting that while these non-shortlisted designs do not meet the access objectives on their own, they did have useful suggestions for design elements. Therefore, design features from these models have been adopted where they strengthen the four shortlisted options in addressing the transmission access reform objectives.

Finally, we note that at least one of the models merits further consideration as part of a separate process even though it did not directly address the objectives of the current review.

The remainder of this chapter outlines for each shortlisted model:

- its high-level design and core features, including how the model can integrate with jurisdictional schemes
- an initial assessment against the transmission access reform criteria
- the key issues to be resolved as part of the next stage of the consultation process.

Going forward, the ESB will work with stakeholders to develop these models and recommend to Ministers a sufficiently detailed design that incorporates one investment timeframe model and one operational timeframe model, including how this can help support jurisdictional REZ schemes.

3.2 Congestion zones with connection fees

Based on stakeholder feedback and further analysis, the ESB proposes to take the REZ adaption of the CMM, as previously recommended in the Post 2025 review, off the table. Specifically, stakeholders raised concern that, under the REZ adaptation of CMM, there will be some market participants that will not receive the congestion rebate. Investor groups perceive this would create risk that could stifle new generation investment, as participants without the rebate will not be able to manage the risk associated with their local price.

We acknowledge these concerns and therefore propose to focus on developing a congestion zone/connection fee-based model. We have made this change in response to stakeholder concerns that exposing generators to congestion charges, without the benefit of a rebate, could inefficiently stifle new entry outside REZs. The congestion zones model also has the advantage that it provides a clear locational signal that can be incorporated into investment decisions.

This option provides a discrete investment timeframe solution, one that can be mixed and matched with a variety of operational timeframe solutions to create a hybrid model. The ESB also considers that this model can be readily integrated with the jurisdictional REZ schemes that are currently being progressed. Such a scheme can be effective with and without REZs which meets the requirement to allow jurisdictional flexibility.

3.2.1 High level design

This model leverages a planning process to segregate the transmission system into zones that reflect the level of available hosting capacity for new generation. The purpose of this process would be to clearly signal to prospective investors which parts of the network are available for further development, which parts are reaching capacity, and those that are already full.

This process could potentially incorporate features proposed by stakeholders or being progressed by jurisdictions, such as:

- the development of a Transmission Statement of Opportunities, as suggested by Iberdrola[13], and/or
- the use of a traffic light system to signal the level of available hosting capacity, as suggested by Neoen,[14]
- leveraging state-based planning documents, such as the Infrastructure Investment Objectives report in NSW.[15]

The information generated by this process would be used to develop a set of locational signals that create incentives for generators, storage and demand side resources to connect in places that align with the broader development of the power system as set out in the ISP (as supplemented by government policy).

This information would be accompanied by a mechanism that provides incentives for generators to locate in a coordinated fashion. This is essential, because at present, it can be profitable for a project developer to locate in part of the system that is already full, so long as they select a location with a favourable generator coefficient (see chapter 2). The objective of the mechanism would be to establish locational signals for market participants that align with the efficient long-term development of the power system. These signals would promote investor confidence that their investments will remain profitable by reducing the risk associated with inefficient subsequent connections.

The ESB proposes that the locational signal take the form of a connection fee. A published schedule of connection fees provides a clear, upfront signal that can be easily understood by investors and can be factored into a project's feasibility modelling. Fees are also versatile in that they can be set at different levels, reflecting forecast congestion at different points of the system. Under this variant, new entrant generators would commit to pay a charge that reflects the long run marginal cost of congestion at their chosen network location. The fee would be fixed at the time of connection, however, just like connection fees currently generators could negotiate how to pay this over the life of the asset e.g. it could be paid to the Transmission Network Service Provider (TNSP) in the form of an annual charge over a defined period.

These charges would be administratively determined via the regulatory framework – for instance by the TNSPs (and approved by the AER) as part of their transmission charging methodology, using inputs derived from the ISP.[16] We acknowledge that it is difficult set a single fee to reflect a project's future impact on congestion, especially given the dynamic market conditions associated with the energy transition. Given that different generation technologies are likely to have different impacts on congestion, it may be appropriate to apply a scaling factor to a generator's connection fee depending on their output profiles. It will also be necessary to consider how providers of congestion relief would be treated. For instance, storage providers that commit to operating in ways that alleviate congestion could be exempted from the obligation to pay a connection fee, or even offered a negative fee.

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13 Iberdrola, Submission to Transmission Access Reform Project Initiation Paper January 2022, p.5.

14 Neoen, Submission to Transmission Access Reform Project Initiation Paper January 2022, p. 6.

15 AEMO Service, Infrastructure Investment Objectives Report 2021, November 2021. Available at: https://aemo.com.au/-/media/files/about_aemo/aemo-services/iio-report-2021.pdf?la=en

16 For clarity, this model is different from the type of connection fees proposed by Shell, which we do not support because it involves a physical access regime – i.e. a do low harm regime expanded to all types of constraints.

There is a trade-off between the accuracy of the locational signal and the simplicity of the process used to calculate the fee. It would be important to ensure that the fee-setting arrangements do not slow down the connection process.

It would be necessary to review and update the status of each zone and associated connection fees at regular intervals. The revised fees would apply to new connections, not parties who have already entered into a connection agreement. The framework could specify tranches so that investors have clarity on how the fees will increase as additional capacity connects within the zone. These arrangements could potentially be applied in conjunction with a batching scheme.

Rather than establishing an entirely new regulatory framework to give effect to this model, there may be scope to leverage elements of the existing market design. In particular, the ESB is considering whether there is scope to design a congestion zones model that adopts aspects of the recent system strength reforms.[17]

This model would result in generators paying for transmission infrastructure but receiving benefits in return, as the connection fees would be set at levels that are designed to result in specified levels of congestion. If a connection fee model were adopted, it would be necessary to consider what should happen to revenue recovered from generators via connection fees. For instance, the revenue could be used to offset transmission use of service charges paid by consumers by funding transmission expansions contemplated in the ISP and selected via the transmission planning process.

This model would be straightforward to apply in conjunction with jurisdictional REZ schemes as the connection fees could be set at levels to encourage/discourage investment in line with jurisdictional schemes. The next stage of the ESB's consultation process will consider a range of matters that affect how the NEM-wide models integrate with jurisdictional schemes.

In particular, we are yet to determine how roles and responsibilities would be allocated. Such roles and responsibilities include classifying the congestion zones and/or setting the fees. There is scope for State planning bodies such as AEMO Services in NSW and VicGrid in Victoria to provide input to a Rules-based planning process conducted by AEMO and/or TNSPs. Alternatively, the State planning bodies could take on functions themselves.

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17 AEMC, Final determination - Efficient management of system strength on the power system, October 2021. Available at: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

Table 6 Core features of congestion zones with connection fees model

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	Generators are incentivised to locate in areas of lower expected congestion because they are charged a lower fee. New generators are charged a locational fee based on an alignment with the ISP and/or a forecast of congestion.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	Efficient connection locations are determined in accordance with the transmission planning framework (as supplemented by government policy). Network is split into zones based on level of current/forecast congestion – with the size of the zones trading off price signal accuracy with practicality. Information regarding status of different network zones is made publicly available.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	Incentives/disincentives are applied in a way that encourage generation investment that aligns with planned transmission investment. If multiple projects are competing for limited transmission capacity, a batching process could come into effect such as that being considered through the AEMO/CEC connections reform initiative.
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	Incumbents are not subject to the incentives/disincentives (as they have already made their location decision).
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	Model features will be developed in detailed design. Once a generator reaches a pre-determined age, they could be excluded from the transmission planning studies that decide zone status i.e. connection fees could be set at lower levels in proximity to end of life generators.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	The model allows for design options where discounts/waivers on connection fees (or other incentive mechanism) could be made available to parties that agree to fund measures that increase hosting capacity or to operate in ways that reduce congestion risk for neighbouring generators.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	Parties that provide congestion relief could be exempted from any disincentives that apply to new generators in congested zones. Potentially - depending on the balance of incentives across the framework as a whole - they could be rewarded for choosing a location where they can provide congestion relief. Given that storage can both worsen or alleviate congestion, depending on whether it charges or discharges, it would be necessary to accompany these arrangements with efficient incentives in operational timeframes.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	Connection fees could be set at levels to encourage/discourage investment in line with jurisdictional schemes. If a project tenders for access rights in a REZ, this cost would be treated as the substitute for a connection fee. Outside of the REZ, the connection fee would continue to apply. There is scope for State-based planning bodies, such as AEMO Services in NSW or VicGrid in Victoria, to take on a role in classifying the congestion zones and/or setting the fees. In States that do not have REZ schemes, connection fees could be used to drive efficient investment outcomes.

3.2.2 Initial assessment

The model provides upfront signals to investors about efficient location decisions in the form of a connection fee. Areas of available or proposed transmission capacity could be identified during early development stages.

Investors would incorporate upfront connection costs into their financial assessment and investment decision. Each project would need to assess the various trade-offs between connection fees and resource availability, price forecasts, contestable transmission costs, MLF, social licence etc. Network information on connection fees and congestion zones (such as a Transmission Statement of Opportunities or traffic light system) would supplement each project's technical engineering report for due diligence purposes on the level of curtailment risk.

Some stakeholders have expressed concern about models that replace the commercial decisions of market players with decisions of central planning authorities. While commercial parties respond efficiently to incentives, if the market design itself is flawed, then commercial decisions made in response to market signals will be distorted. For the market design to provide accurate congestion signals, LMPs are required. However, market participants have indicated that they do not want to be exposed to LMPs because they are hard to predict.

LMPs do not increase uncertainty in and of themselves. Rather, LMPs reflect congestion risk transparently, in a form that is more easily incorporated into financial models. The risk of congestion already exists in the form of volume risk i.e. a generator may not be dispatched for as much as they want, even though they are in-merit, due to transmission congestion. As such, it is subject to opaque technical criteria that may not be fully reflected in investment decisions.

If market participants are unwilling to be exposed to prices that embody the cost of congestion as has been clear in stakeholder feedback to date, then our alternatives to address the problems set out in Chapter 2 are:

- A central body attempts to manage congestion on behalf of market participants, or
- We continue to manage congestion using opaque and changeable technical criteria, with its consequences of poorly located investments and higher investment risk.

Under the congestion zones model, planning bodies are effectively taking on responsibility for forecasting congestion. The connection fee model extends the congestion zones model by giving market participants financial incentives to connect in line with the optimal development of the system, given those forecasts.

Some stakeholders have suggested that better information provision is sufficient to promote efficient locations decision by generators. Recent experience in the NEM suggests that congestion will not necessarily stop investors from investing. For instance, the problems arising the West Murray Zone are well publicised[18] and yet there are still a substantial number of connections in progress.

The previous chapter explained how the current market design makes it profitable for generators to cannibalise the output of their neighbours. We question whether it is prudent to design a market where efficient whole-of-system outcomes are dependent on the altruism of market participants to be willing to forego profitable opportunities. A better approach is to design the market so that efficient decisions and profitable decisions are aligned.

18 AEMO, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/west-murray

This option takes effect at the point of a project's investment decision. There is no impact in the operational period.

Table 7 Initial assessment of congestion zones with connection fees model

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	New investments are encouraged to locate in areas of available or proposed capacity consistent with ISP transmission investments. The model can be deployed across the NEM with a consistent methodology, and readily accommodate and be flexible to jurisdictional REZ schemes.	Differentiated fees methodologies by jurisdiction could distort investment.
Appropriate allocation of risk	New generators appropriately bear the costs of congestion they cause in the form of a connection fee. Revenue can be transferred to customers via TUOS or to taxpayers if part of a state scheme.	The model relies on a regulatory process to assess available hosting capacity and set fees. To the extent that forecast error misdirects investment, the additional costs are borne by customers – noting that there would have to be a material error in the regulatory process for this to result in worse outcomes than the status quo, given that at present the fee is effectively zero.
Manage access risk	Investors have greater clarity on upfront locational costs and greater confidence that their project will not be undermined by inefficient subsequent connections. The model encourages connections in areas of actual or forecast available transmission capacity.	Access risk is managed insofar as the modelling is accurate. If the modelling is inaccurate, there may be an inefficient level of congestion or under-utilisation of the network.
Effective wholesale competition		The model disadvantages newer entrants relative to incumbents insofar as incumbents were not required to pay a fee when they connected. There may be scope to design the process for setting connection fees so that the fees are set at levels that do not take into account the presence of generators that have reached a specified age.
Implementation considerations	The model is given effect by the transmission planning framework and does not require changes to market systems.	There is potential for significant complexity – both in terms of cost and timeframes - in the upfront assessment and modelling to determine the marginal cost of congestion. There is a trade-off between the accuracy of the locational signal and the simplicity of the process.
Support for jurisdictional schemes	Supports jurisdictional schemes by charging connection fees that encourage investment in REZs and discourage investment that undermines REZs.	

This model has been shortlisted for further consideration. A connection fees model has the advantage of providing up front clarity to investors. The CMM + connection fees model was the ESB's second ranked model during the Post 2025 process and was preferred by several stakeholders. A model that utilises connection fees could equally be applied in combination with the CRM. It also responds to a key concern raised by stakeholders in relation to the CMM-REZ because under this approach no generator would be exposed to the congestion fee without the benefit of a congestion rebate.

Key questions

- What form of incentive should be used to influence generator location decisions?
- What methodology should be used to calculate the efficient hosting capacity of the network for each zone?
    - How does this methodology reflect differences in the output profiles of different generator types?
- How should the model treat multiple generators seeking access to the same part of the network?
- Who should be responsible for administering various aspects of the framework?
- How should connection fees be calculated?
    - What is the correct balance between accuracy and simplicity/transparency?
    - What should happen to revenue paid by generators?

3.3 Transmission queue

Under its original design, the grid access reform model[19] proposed a two-part approach:

- investment timeframes – modifying open access to incorporate:
    - queuing for transmission capacity
    - transmission charges to improve a generator's queue position.
- operational timeframes – rule changes that:
    - prioritise renewable generators and energy storage in preference to thermal generators when they are tied bids and transmission capacity is constrained
    - use average loss factors for settlement purposes.

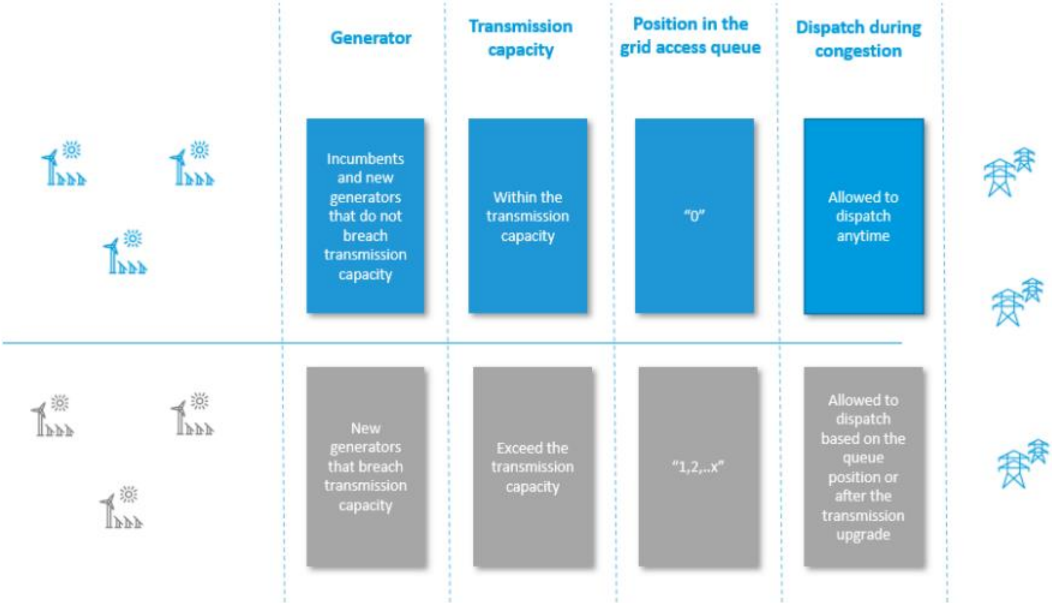
This section focuses on the first part of the model design during investment timeframes, which has been chosen as a shortlisted model for further consideration. Appendix D.1 provides detail on the tie-breaking rule during operational timeframes. Average loss factors do not address the transmission access reform objectives and have not been pursued in this consultation process.

3.3.1 High level design

This model establishes a transmission queue that confers priority rights in operational timeframes. Priority rights are allocated to incumbents and thereafter on a first come first served basis (if the network has spare capacity) or via auction (if it is over-subscribed).

19 Model design is based on the proposal submitted by the Clean Energy Investor Group (CEIG) Report on Transmission Access Reform, February 2022.

Figure 10 Overview of the transmission queue



Source: Castalia Ltd, [Transmission access reform Report to Clean Energy Investor Group (CEIG)] p.21, February 2022

The queue mechanism would operate as follows:

- Priority rights over transmission capacity is allocated on a 'first-come first-served' basis.
- Position '0' is granted to incumbent generators and new entrants connecting to spare transmission capacity.
- Position '1, 2, 3…' is allocated to subsequent entrants.

Under the original design of the model, in the event of a constraint and tied bids, generators would be curtailed in order from the highest to lowest queue position, that is, on a "last in, first curtailed" basis. The ESB proposes a modification to way that queue numbers confer priority rights on market participants, which is discussed on page 35. However, other aspects of the model could form the basis of an investment timeframe access solution.

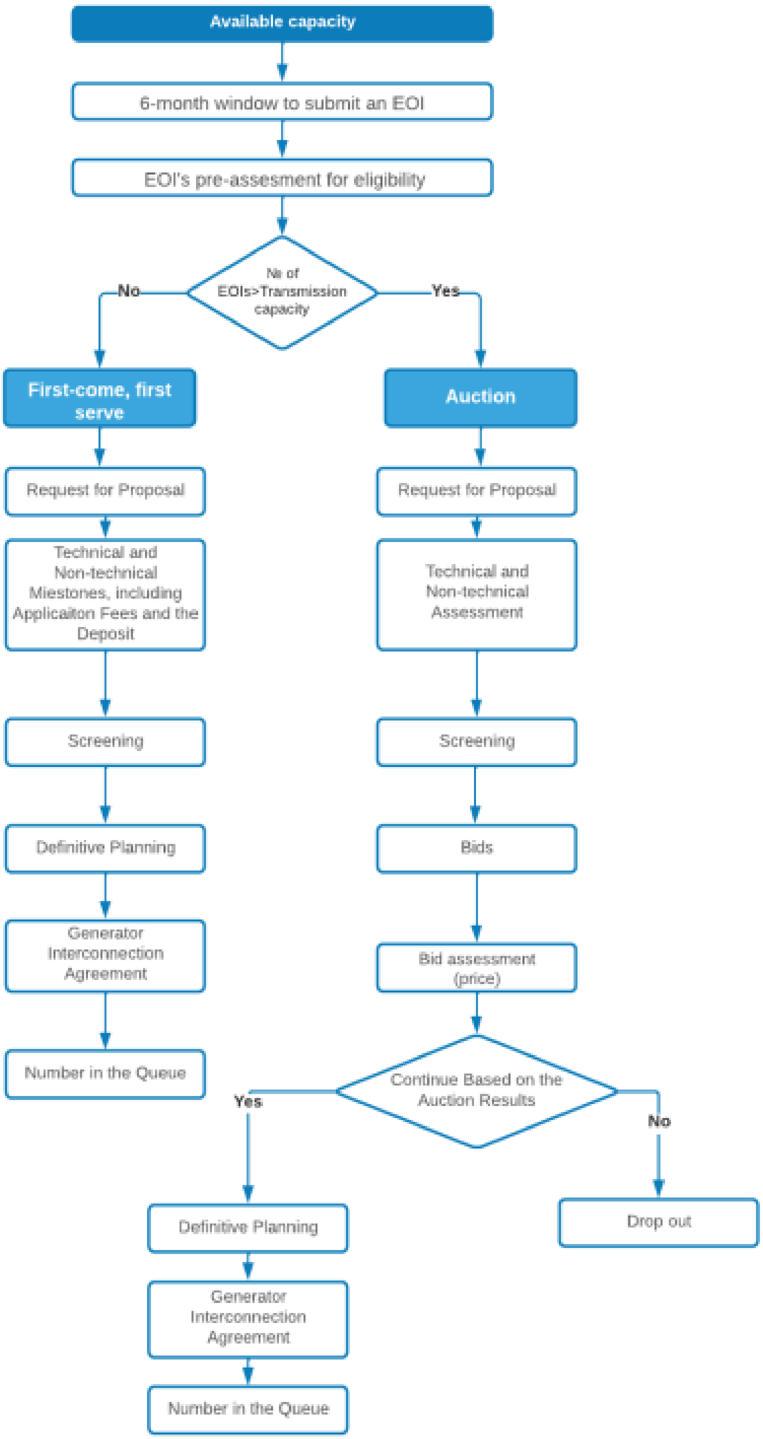
Figure 11 (next page) illustrates how an expression of interest (EOI) process is used to trigger one of two queue allocation methods:

- First come, first served approach (where demand for access is less than transmission capacity)
- Auction (where demand for access is greater than transmission capacity).

AEMO would undertake analysis with reference to historical data to determine the available transmission capacity. The analysis would incorporate thermal capacity, voltage and stability requirements.

The EOI process could include minimum eligibility thresholds including technical and non-technical requirements. If an auction is triggered, proponents would be evaluated based on their bid price. If the tender process for queue positions generates surplus revenue (beyond the costs of running the tender), surplus revenue should be returned to customers in the form of a reduction in network charges, or used in other ways, such as paying for programs that will increase the social license of proposed transmission investments. Projects would have to commence construction within 2 years of being allocated a queue position.

Figure 11 Generator queuing process



Source: Castalia Ltd, Transmission access reform Report to Clean Energy Investor Group (CEIG) p.29, February 2022

The model also includes a safety valve for new connecting generators who are faced with a high queue number to manage their access risk by electing to pay a transmission charge or invest in energy storage. If generator is willing to fund investment to offset the additional congestion that they cause, they would be given a queue number of "zero". A new regulatory process would be established with oversight of TNSP charges, timeframes and contract terms. Generator-paid transmission investment would not require approval via RIT-T processes.

New entrants could also install storage and dispatch during periods when there is no shortage of transmission capacity. A high queue number is irrelevant to dispatch outcomes if there is no binding constraint e.g. dispatching in off peak periods outside of intervals of coincident VRE.

Modified design

The original design proposes to trigger the queue mechanism in the event of a binding constraint and tie-breaking bids. When multiple generators have bid the same price and MLF, the model proposes that the dispatch algorithm would dispatch based on their order in the transmission queue.

Figure 12 Order of decision making in dispatch order

Source: Castalia Ltd, Transmission access reform Report to Clean Energy Investor Group (CEIG), p.24, February 2022

Generators that connect to the grid earlier would receive priority dispatch over generators that connect later.

However, an issue with this approach is that tie-breaker rules rarely come into play due to the impact of generation coefficients (contribution factors).[20] Instead, race to the floor bidding and precision of contribution factors gives rise to 'winner takes all' outcomes. This current market design issue is discussed in Chapter 2 and Appendix B. As a result, it is not clear that the original design would be effective in protecting the access of generators, even those with low queue positions.

The ESB is exploring modifications that apply the queue position in ways that help investors to manage their access risk. For instance, the queue mechanism could be used to:

- allocate rebates in a CMM model (section 3.4) or
- determine the eligibility of generators to sell congestion relief in a CRM (section 3.5) or
- confer access rights in jurisdictional REZ schemes.

These modifications would overcome the shortcomings of relying on tie-breaker rules by applying the queue right to financial arrangements rather than physical dispatch. These modifications are discussed in sections 3.4 and 3.5.

The ESB considers that this aspect the transmission queue model – namely, the nature of the priority right associated with a low queue position – needs to be modified for the model to work. We will work with stakeholders to explore potential solutions, including the options noted above. Other aspects of the model, such as the process for allocating queue rights, show promise and we will continue to further develop the model as part of the detailed design process.

20 Each generator or interconnector affected by a constraint has a coefficient allocated to it within the constraint equation, which reflects the impact it has on the constrained transmission line. For example, if a one MW reduction in output of a generator decreases flow on the constrained line by one MW, the coefficient is +1. Typically, the further away a generator or interconnector is located from the constrained line, the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.

Table 8 Core features of transmission queue model

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	When congestion occurs, generators with tied bids and identical participation factors are dispatched in the queue order. When the coefficients of the congested generators are not identical, for example in the presence of a loop on the transmission network, dispatch reverts to the status quo, with generators being dispatched in order of contribution factor by the dispatch engine.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	The model applies to existing and future transmission networks as per the ISP. Efficient connection locations are identified based on the transmission capacity available.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	If EOIs are less than the available or proposed transmission capacity, first come first served is applied. If EOIs are greater than the transmission capacity, an auction is held and proponents assessed based on price. Projects must commence construction within 2 years of being allocated a queue position.
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	Incumbent generators are treated as equal first in the connection queue (or pro-rated according to current rules if incumbent generation exceeds transmission capacity).
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	The detailed design process will consider the duration of queue rights. The rights should apply for a period that is long enough to enable investors to finance their projects, while still retaining a level playing field for new entrants.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	Option for new generators to fund investment to increase transmission hosting capacity in return for an improved position in the queue.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	Opportunity for generators to improve their position in the queue through transmission charges (to augment local transmission capacity or install storage and seek the right to dispatch during periods when there is no shortage of transmission capacity). Energy storage is subject to same queuing terms as generators.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	Priority queue positions could be made available to REZ generators. Outside REZs, the NEM-wide access regime could support REZs by allocating low priority queue positions to generators who wish to connect in locations that would undermine the access of REZ generators. Model is compatible with existing proposed physical access regimes e.g. NSW. States without REZ access regimes can utilise this model.

3.3.2 Initial assessment

The transmission queue would protect the incumbency dispatch rights of generators by creating a queue that confers priority rights during times of congestion. The queue would encourage investors to build generation capacity in locations that either would not have a negative impact on congestion, or where they are willing to accept a higher number in the queue and congestion risk during periods of high generation. The modified version of this model has been shortlisted for further consideration through this process.

Table 9 Initial assessment of (modified) transmission queue model

Assessment criteria	Pros	Cons
Efficient market outcomes – investment	Long term signals incentivise generators to locate where capacity is available. The model allows investors to make informed decisions about the level of curtailment they will face within the available transmission capacity (projects can proceed if it is economically viable).	Analysis of available transmission capacity relies on modelling and assessments performed by a central planner and are open to central planning error. Risk that an additional hurdle during the connection process (including the EOI and/or auction process) will slow or deter investment. *The ESB notes that this model is conceived as an access queue rather than a connection queue.*
Appropriate allocation of risk	Parties with strong positions in the queue face reduced congestion risk. Parties that cause congestion face higher congestion risk. Model shifts some costs to generators through auctions for queue rights and transmission charges for generator led transmission development.	
Manage access risk	Improves investor certainty by providing a local preferential access right that does not degrade over time. It is not firm but it is 'firmer' than the current open access regime.	The queueing system is not fully firm given the complexity of the meshed transmission network. The model may lead to inefficient levels of congestion depending on the forecast versus actual generation outcomes.
Effective wholesale competition	The model provides generators with improved confidence that their access will not be degraded over time. There is no prohibition on connections; generators can choose to connect in any location but they will need to assess their queue position and associated congestion risk.	There is a risk that queueing may limit or damage contract market liquidity. Further consideration is required of the duration of queue rights to ensure that they do not stifle competition. Further consideration is required of EOI eligibility criteria to ensure that advantageous queue positions are not awarded to generators that won't reach financial close, which could deter other genuine investment.
Implementation considerations	The original model proposes a relatively simple approach to address transmission capacity constraints and disorderly bidding – however further work is required to ensure the model works.	It may be challenging to implement EOIs and auctions within the defined time periods without disrupting the timely investment of new generation. A queue position may be allocated but held in limbo while proponent works to complete grid studies and finalise the connection agreement.

Assessment criteria	Pros	Cons
Support for jurisdictional schemes	Supports jurisdictional schemes by making available queue positions that encourage investment in REZs and discourage investment that undermines REZs.	

This model has been shortlisted. The ESB has heard from stakeholders that this model has several features that are attractive to market participants:

- generators receive a form of priority right based on the timing of their connection or the outcome of an auction
- the use of auctions helps to overcome challenges associated with connection queues in other jurisdictions
- investors are provided with tools to manage their access risk, and
- new entrants can continue to choose where to locate but they face the associated risk of locating in congested areas.

The impact of the transmission queue on an investment decision depends on the detail of the model design. Investors would want visibility as to how the queue position '0, 1, 2, 3' would translate into price and dispatch outcomes. The model design needs to be modified so that the queue mechanism does not apply to tie-breaker rules. Instead, the queue mechanism could be incorporated into:

- the metric used to allocate congestion rebates between generators under the CMM or
- the initial process to establish who buys and who sells congestion relief, or
- jurisdictional REZ schemes.

Resolving this issue will be key to the viability of this model, particularly if it can dovetail with jurisdictional REZ schemes and flexibility.

The ESB observes that a variant of the "safety valve" feature could be incorporated as an add-on to any investment timeframe solution. For it to be a realistic option for new connecting generators, it would be necessary to develop a mechanism to ensure that individual generators are not required to fund lumpy transmission investments that benefit multiple generators. It would also be necessary to review the regulatory framework that applies to transmission networks, to ensure that TNSPs do not have the incentive to recover higher revenues by requiring generators to pay for negotiated services where the investment could have been funded as a shared transmission services.

Key questions

- How should a generator's queue position manifest in operational timeframes?
- 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)?
    - How does this methodology reflect differences in the output profiles of different generator types?
- Who should be responsible for administering various aspects of the framework?
- Can queue positions can be traded?
- Should energy storage be subject to the same queuing terms as generators?
- Should the framework encourage efficient retirement decisions for end-of-life generators and if so, how?
- 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?

3.4 Congestion management model (CMM) with universal rebates

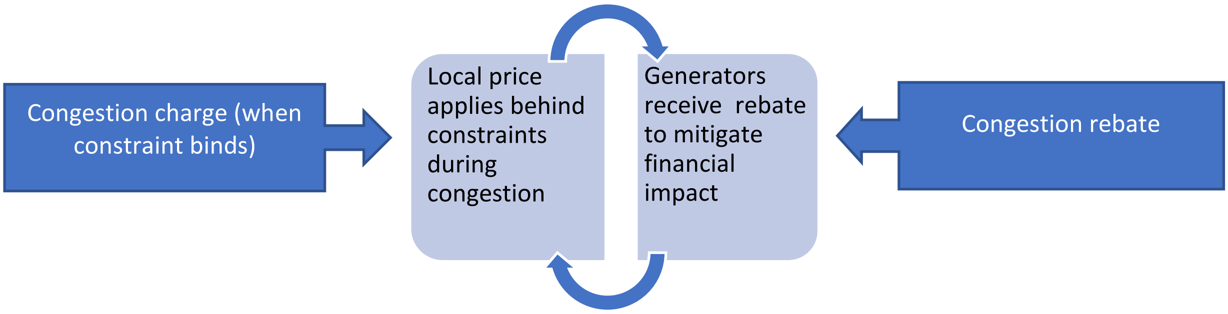
The model establishes a single, combined-bid energy and congestion market – in this model generators and batteries would receive rebates if congestion occurred. This model was previously referred to as the vanilla CMM in the Post 2025 market design process.

We understand that many stakeholders have raised concerns with the congestion management model in previous submissions to this work. We have sought to address some of these concerns throughout the discussion in this section and explore ways that the design could be amended.

3.4.1 High level design

When a constraint is not binding, the current market design is unchanged. All wholesale market participants would be settled at the RRP adjusted for loss factors. When a constraint is binding, the CMM introduces a dual mechanism of congestion charges and congestion rebates.

Figure 13 Simplified illustration of CMM



Source: ESB

When a constraint binds, all scheduled and semi-scheduled market participants that appear in the left-hand side of the constraint equation would face a congestion charge. The congestion charge would be calculated on a $/MWh basis reflecting the generator's impact on congestion in the dispatch interval. Specifically, this charge is calculated as the change in the cost of dispatch were a binding constraint to be relaxed by a small degree, multiplied by the generator's contribution factor in the constraint. When the market participant is not participating in a binding constraint, its congestion charge will be zero.

In the face of the congestion charge, the profit maximising strategy for a generator behind a binding constraint is to bid more closely to the true cost of its generation (i.e. in line with short-run marginal costs). This reduces the cost of dispatch because the dispatch engine will select the actual lowest cost combination of generators.

The net effect of receiving the RRP and paying the congestion charge is that generators face their locational marginal price. Indeed, the dispatch engine already calculates shadow locational marginal prices in this way, by deducting the marginal impact of congestion from the RRP. Generators are disincentivised from bidding to the market floor price because they risk incurring high congestion charges.

When congestion occurs, all generators that appear in the constraint would receive a congestion rebate, calculated for each dispatch interval and funded from the collective revenue received from the congestion management charges relating to that constraint in that dispatch interval. For the avoidance of doubt, rebates would be made available to both incumbents and new entrants, irrespective of whether they are in a REZ.

The size of the rebate would be determined in accordance with a pre-determined allocation metric. A range of options for the allocation metric can be tailored to meet various objectives, such as:

- **Maintain status quo outcomes —**existing generators should, ideally, be no worse off financially under CMM than under the status quo. The rebate could be designed to replicate the outcomes that would occur if all constrained generators bid to -$1000, including taking into account the impact of contribution factors on current dispatch patterns. This option would give outcomes similar to the CRM except that it occurs automatically rather than via a separate ancillary services market.
- **Sharing of risks —** congestion impacts can be shared between constrained generators to reduce financial risks to individual generators. For example, the CMM could be designed to move away from "winner takes all" outcomes, where small differences in contribution factors have a large bearing on the profits of individual generators in a looped flow.
- **Similarity to actual dispatch —**differences between access and dispatch are settled at LMP, which creates some complexity and basis risk for generators, so ideally these are minimised. Under an inferred economic dispatch approach, rebates could be payable to generators with the lowest short term marginal cost. A regulatory process would be established to infer each generator's short term marginal cost. Rebates would be allocated based on what the economic dispatch would have been if generators offered these inferred costs.
- **Increased certainty for generators with priority access rights —** for example, the allocation metric could be designed to reflect queue status (as established via the transmission queue model outlined in section 3.3). Generators with a '0' position would have greater entitlement to rebates than generators with a '1, 2, 3…' position. The ESB is working with stakeholders to develop a mathematical formula for how this could work.

- **Simplicity and transparency —** the algorithm and its outcomes should be easy for stakeholders to understand. Rebates could be made available to generators in proportion to their availability, where access is scaled by a universal factor to ensure that dispatch is feasible.

As the purpose of this model is to drive efficient operational outcomes, it is critical that the allocation metric does not distort efficient bidding incentives. It therefore needs to be independent of dispatch outcomes. When models similar to the CMM were proposed in the past,[21] it was suggested that the best metric to achieve this objective is generator availability. Availability has the following advantages:

- It is one of the factors that drives existing dispatch outcomes, which means that financial outcomes will be broadly aligned with the status quo.
- It fits well with the risk that generators are trying to manage i.e. the risk that they will be dispatched for less than their availability due to congestion.
- It is a well-established, commonly used and monitored metric. [22]

There are also some refinements that could be made to availability, particularly with respect to out of merit order generators. In its simplest version, the CMM allocates rebates on the basis of availability regardless of whether the generator would have wanted to be dispatched at the prevailing RRP (i.e., even where RRP is less than generator cost). High marginal cost plant (i.e. peaking plant) would receive a windfall gain at the expense of low variable cost plant. This is because the low marginal cost

21 International Power, AGL, TRUenergy, Flinders Power, LYMMCo, A congestion management regime without allocating rights, 4 April 2008. Available at: https://www.aemc.gov.au/sites/default/files/content/bd0bae75-0d9a-4c14-a2db-de275ab88209/International-Power%2C-AGL%2C-TRUenergy%2C-Flinders-Power%2C-Loy-Yang-nbsp%3B-4-April-2008.pdf

22 For a scheduled unit, the total *availability capacity* as defined in the rules. For non-scheduled generators the *unconstrained intermittent generation forecast* as defined in the rules.

generators are obliged to share their rebates with generators who would not normally have been dispatched in that interval.

To avoid this outcome, we could preclude out of merit order generators from receiving a share of the settlement residue if the RRP is low e.g. by precluding peaking plant from receiving a rebate if the RRP is less than $300 MWh. However, this refinement has the potential to become complex, particularly as we can't use generator bids to determine merit order (because to do so would re-introduce the incentives for disorderly bidding that we're trying to eliminate).

The next stage of the ESB's consultation process will involve working with stakeholders to explore the pros and cons of the various design choices for allocation metrics. Among other things, we would like to explore how different allocation metrics might support efficient hedging arrangements in the contract market both now and in the future, and how these allocation metrics may impact investment decisions for participants.

The ESB's initial thinking is that since the settlement residue is intended to hedge generators against congestion, it should only be returned to those generators that are affected by congestion in a particular dispatch interval. That is generators who participate in the binding constraint, are available and are in-merit, meaning that they would have been dispatched but for the congestion. In order for settlement to balance, the allocated rebates must also represent a feasible dispatch. This means that the sum of rebate capacity allocated (in MW) must not exceed the capacity of the right-hand side of the constraint in question.

Table 10 Core features of CMM with universal rebates

Feature	Model proposal
Efficient dispatch outcomes How does the model dispatch the cheapest available combination of resources to securely meet demand?	When congestion occurs, market participants are subject to a congestion charge that reflect the marginal cost of congestion at their location.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to help to alleviate congestion?	When congestion occurs, two way and demand side participants can access lower prices (equivalent to a negative congestion charge).
Managing inter-regional flows How does the model ensure efficient use of the transmission system when inter regional flows are affected by congestion?	This model removes the need for clamping in the event of counter-price flows, because generators affected by congestion receive the local marginal price and the congestion rebate. The settlement residues flowing into of the pool of rebates reflect the RRP where the energy is consumed.
Allocating the value arising from regional pricing How does the model allocate the value arising from the use of regional pricing?	Depends on rebate allocation metric. Options include various combinations of applying the queue mechanism (section 3.3), availability, contribution factors, inferred economic dispatch (i.e., assumed costs). For example, the status quo winner takes all arrangements could be largely replicated by allocating rebates on the basis of ascending order of contribution factors, capped at each generators' availability.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model can be applied in conjunction with State government REZ schemes because REZ schemes are focussed on investment timeframes rather than how those assets operate.

3.4.2 *Initial assessment*

In investment timeframes, the incentives do not appear to be materially better or worse than at present. All generators receive rebates irrespective of where they locate, so this model does not provide a signal to locate in places where the generator does not increase congestion. If new generators connect in congested locations, the value of rebates to all generators affected by the constraint would get smaller as the rebate "pie" is shared between more parties. Hence this model needs to be complemented by an investment timeframe solution.

Some respondents to the project initiation document[23] (including Flow Power and Tilt Renewables) have suggested that the CMM would impact the contract market, including causing contracts to be renegotiated and reducing liquidity.

The CMM will require projects to assess the impact of congestion on both volumes (as per status quo curtailment studies), and two new considerations: the impact of congestion charges and rebates. For projects that are contracted (e.g. with power purchase agreements (PPAs)), a basis risk emerges between the price settled for consumers/retailers (RRP) and the price settled for generators (LMP). The ability of the investor to manage this basis risk depends on the allocation, length and certainty of congestion rebates.

Going forward, we will work with stakeholders to design the congestion rebates in way that make them an effective tool for managing the difference between LMP and RRP. If this model is applied in conjunction with an investment timeframe solution which acts to reduce the risk of unexpected congestion, then the overall risk to investors is reduced. Congestion risk already exists and is currently borne by constrained down/off generators.

While the impact on contracts depends on what terms have been agreed, the ESB has considered this feedback and considers that it unlikely that renegotiation would be required in most cases because:

- The RRP paid by customers is unchanged.
- All generators will receive congestion rebates.
- On balance, we expect the impact of the CMM on parties with PPAs (typically VRE generators) to be benign because low-cost generators will be less likely to be curtailed from race to the floor bidding behaviour by high-cost generators.
    - However, any individual generator or their counterparty may be worse off, depending on their contractual terms and whether the generator is a winner or a loser under the current winner takes all arrangements.

Collectively, generators will be better off under the CMM, because of the efficiency gains that arise, and because they receive the intra-regional settlement residues in the form of rebates. Within this collective result, some generators may face more risk than currently while others will face less risk. A key focus of the ESB's next stage of work will be to model the impacts so that market participants can better understand how they are likely to be affected by various options for transmission access reform.

To the extent that there are still concerns with respect to existing contracts, the transitional arrangements for the access scheme can be designed and implemented in such a way that minimises the costs. Taking such aspects into consideration is not unusual when considering changes to the NER and has been done regularly in the past (e.g. when 5-minute settlement was introduced).

23 Submissions to the project initiation paper are available here: https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/transmission/congestion-management-mechanism

Some respondents to the project initiation paper[24] (including CS Energy and Neoen) suggested that CMM will not eliminate inefficient bidding behaviour as generators will find new ways to maximise profits. Under the CMM, the market design will more closely reflect underlying power system conditions, so that it is in generators' self-interest to bid in a way that more closely reflects the efficient cost. We note that LMP-based models have successfully improved the efficiency of dispatch outcomes in other jurisdictions. However, there are some aspects of the CMM design that could present opportunities for gaming and we are seeking to avoid this outcome. The treatment of out of merit order generators is a particular example.

Table 11 Initial assessment of CMM with universal rebates

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	The model creates new business opportunities for batteries and other types of storage to be paid to alleviate transmission congestion, which encourages them to locate where these services are most needed.	As all generators receive rebates, this model does not provide upfront locational signals to new entrants. Should be implemented in conjunction with an investment timeframe solution.
Efficient market outcomes – dispatch	Generators are incentivised to bid more closely to their marginal cost, which drives more efficient dispatch outcomes and provides signals for congestion relief. Demand-side and two-way technologies can access lower prices/larger price spreads relative to the RRP. Hence they are appropriately rewarded for providing congestion relief.	
Appropriate allocation of risk	Improved bidding incentives means that customers do not have to pay higher prices as a result of inefficient dispatch outcomes.	The available pool of congestion rebates is shared between generators. As new generators connect, existing generators will receive a slimmer slice of the rebate "pie". For this reason, the model should be complemented by an investment timeframe solution.
Manage access risk	All generators receive rebates to mitigate their exposure to LMPs. The model provides locational signals for load/two-way technologies to access lower prices in congested parts of the NEM, which may result in longer-term access improvements.	The impact on the investor's risk depends on the rebate allocation metric. A range of options are available for consideration.
Effective wholesale competition	The model design encourages parties to bid their marginal cost and addresses disorderly race to the floor bidding and clamping.	When designing the rebate, it will be necessary to screen options to ensure they do not create new opportunities to distort competitive outcomes to maximise the rebate.

24 Submissions to the project initiation paper are available here: https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/transmission/congestion-management-mechanism

Assessment criteria	Pros	Cons
Implementation considerations	The model is relatively straightforward to implement. It requires changes to settlements but not dispatch. Dispatch outcomes are affected by the impact on participants' incentives.	
Support for jurisdictional schemes	The model supports REZs (and interconnector investments) by making sure that transmission infrastructure is utilised efficiently. It also creates incentives for storage and flexible load to locate within REZs and operate in ways that helps to alleviate congestion during periods of high VRE output.	

A key advantage of this model is that it is relatively straightforward and low cost to implement into the market systems. It results in simple bidding arrangements; market participants only submit one bid rather than separate bids for the energy and congestion markets under the CRM model (section 3.5).

Going forward, a key outstanding matter for consideration is the allocation metric used to determine each generator's share of the congestion rebates. Generators require clarity on this feature of the CMM so that they can assess how the model affects them.

Key questions

- What objective should we seek to achieve when selecting a metric to allocate rebates between generators?
    - Should we remove the "winner takes all" characteristics implicit in the current specification?
- What are the consequences of the CMM in terms of bidding incentives?
- Should we adapt the model to preclude peaking generators from receiving rebates when the RRP is low?

3.5 Congestion relief market (CRM)

This model creates a separate congestion ancillary market that co-optimises the bid with the energy market and other ancillary markets. Participants can choose whether or not to participate in the ancillary market, just as they can with existing ancillary markets.

3.5.1 High level design

The CRM[25] is an ancillary services market for the provision of congestion relief in operational timeframes. The CRM would enable market participants to pay or receive additional money to adjust their dispatch up or down, based on the initial dispatch solution for a particular dispatch interval. The trading of congestion relief would enable low-cost participants to be dispatched over higher cost participants through a compensation process. This would lead to more efficient dispatch with lower cost generation being dispatched.

The CRM would enable market participants to trade "congestion relief" every five minutes based on an initial dispatch run. This would happen as follows:

- Market participants' (initial) dispatch of energy would be determined as per the status quo arrangements. This would determine the prospective buyers and sellers of congestion relief:
    - Generators (loads) that participate in a binding constraint and are initially dispatched (not consuming) are prospective sellers of congestion relief for that constraint.
    - Generators that participate in the binding constraint and are initially constrained off (fully or partially) are prospective buyers of congestion relief.
- Buyers and sellers would bid/offer into a separate CRM for each binding constraint.
- The quantity being bid/offered would be adjusted by each participant's contribution factor in the constraint.
- The market clears, determining a clearing price and quantity of congestion relief traded.
- If a participant sells congestion relief, then the quantity that it sells is settled at the congestion relief price, not the RRP.
- If a participant buys congestion relief, the quantity of relief is settled at the congestion relief price (participant makes payment), and the quantity of energy dispatched is settled at the RRP (participant receives payment).

It is not compulsory for participants to bid/offer into the CRM. If a participant is dispatched and it does not make an offer to sell congestion relief, it would simply be paid at the RRP for its dispatch quantity.

If a transaction is made in the CRM, NEMDE will co-optimise the outcomes of the CRM alongside the energy and FCAS markets. The initial energy dispatch will be adjusted to reflect the outcomes of the CRM. If there is a solution, this will result in a lower cost, or more efficient, dispatch outcome.

The ESB would like to explore whether stakeholders support the retention of the winner takes all approach to determining who are the buyers and sellers of congestion relief, or whether there is support for arrangements that share the costs of congestion in a way that is more transparent and predictable. Alternative arrangements could retain the use of coefficients to deliver efficient dispatch outcomes and locational signals and spread the financial impact on constrained generators more evenly and/or predictably.

25 Model design is based on the proposal submitted by Edify Energy, Edify Energy Response to Post 2025 Market Design Options, initially submitted June 2021 and re-submitted January 2022

Table 12 Core features of congestion relief market

Feature	Model proposal
Efficient dispatch outcomes How does the model dispatch the cheapest available combination of resources to securely meet demand?	When congestion occurs, market participants can buy/sell congestion relief.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to help to alleviate congestion?	Storage, demand response providers, and parties that benefit from disorderly bidding have the opportunity to sell congestion relief to curtailed generators.
Managing inter-regional flows How does the model ensure efficient use of the transmission system when inter regional flows are affected by congestion?	Trading in the CRM is expected to reduce the incidences of counter-price flows but further work is required to examine this issue.
Allocating the value arising from regional pricing How does the model allocate the value arising from the use of regional pricing?	Initial dispatch run establishes buyers and sellers of congestion relief, which retains the status quo allocation of value (including winner takes all).
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model can be applied in conjunction with State government REZ schemes because REZ schemes are focussed on investment timeframes rather than how those assets operate.

3.5.2 Initial assessment

The CRM has been shortlisted. The ESB has heard from stakeholders that this model has several features that are attractive to market participants:

- It gives market participants autonomy over whether they choose to participate.
- It transparently rewards parties who alleviate congestion.
- It provides a clear path for developing supporting contractual arrangements.

While this model may have certain advantages, it would also have significantly higher implementation costs than the CMM (at least in terms of systems costs). This is because a separate ancillary market would need to be built, requiring significant changes to both AEMO and participant systems. Therefore, in any assessment the benefits that would be realised under this approach would need to be commensurately higher.

AEMO provided an indicative, preliminary cost of $300m +/- 30%[26] for a similar set of systems changes during the Coordination of Generation and Transmission Investment Review.[27] Although some of these costs were specific to the operation of a market for Financial Transaction Rights (FTRs), which would not be relevant in this case, a material proportion of the costs identified would likely be applicable for the CRM. In comparison, AEMO's preliminary estimate of system costs for the congestion management model were around $10m, up to $20m.[28]

26 10 year total cost of ownership (TOC). Note this was an indicative, preliminary estimate.

27 Submission to the interim report on Transmission Access Reform – AEMO: Available at: epr0073 - _aemo_submission_cogati_interim_report_19oct2020.pdf (aemc.gov.au)

28 ESB, Post 2025 Market Design Final Advice to Ministers, Part C, July 2021, p. 64.

Further work is underway which will help to consolidate our view of the implementation options and expected costs. Being more expensive does not necessarily preclude a model from being selected, but the additional costs would need to be offset by commensurately higher benefits relative to the alternative options.

A second matter requiring further consideration is that under the CRM, a preliminary run using the status quo arrangements establishes the starting point for buying and selling of congestion relief. If the generators are disorderly bidding and hence bidding to the price floor, their coefficients will play a key role in determining who gets dispatched in the preliminary run. Generators with a lower coefficient will have the opportunity to sell congestion relief to neighbouring generators with a higher coefficient. Effectively, the lower coefficient generators are agreeing to raise the price of some (or all) of their output, in return for a congestion relief payment. This would change the lower coefficient generators' position in the bid stack, with the result that some of their neighbour's output is now able to be dispatched (but they have had to pay to be able to so).

Generators would have an incentive to sell congestion relief to neighbouring generators if they have higher costs than their neighbours, which creates an arbitrage opportunity. In the short term, 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).

Because an ability to buy and sell is determined by coefficients, there remains the incentive to invest in locations which, while not optimal from a whole of system perspective, means the new generator is consistently a seller by virtue of having a favourable coefficient. Necessarily this means some other generator that was previously a seller becomes a buyer. Hence, the CRM does not fix the problem of generators "cannibalising" each other's output.

As a consequence, the CRM does not provide a solution to the problems identified in the investment timeframe.

Indeed, there is even a theoretical prospect that 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. While it is not clear that the CRM would be valuable enough to distort investment decisions in this way, there is a prospect that payments for congestion relief could provide a windfall gain that defers efficient retirement decisions. This risk shares parallels with the issue relating to out of merit order generators in the CMM. The equivalent solution is to amend the initial dispatch run that establishes who buys and who sells congestion relief.

Table 13 Initial assessment of congestion relief market

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	The model creates new business opportunities for batteries and other types of storage to be paid to alleviate transmission congestion, which encourages them to locate where these services are most needed.	As it retains winner-takes-all, this model does not provide upfront locational signals to new entrants. Should be implemented in conjunction with an investment timeframe solution.
Efficient market outcomes – dispatch	The model provides a transparent price signal to relieve congestion. It has potential to achieve efficient dispatch outcomes.	Depending on how the model is implemented, the price signal for congestion relief may be opaque.
Appropriate allocation of risk	The CRM allows for price discovery of congestion relief services and enables parties to assess congestion costs and participate in congestion relief. Improved bidding incentives means that customers do not have to pay higher prices because of inefficient dispatch outcomes	New entrants can still cannibalise the output of incumbents, so the model should be complemented by an investment timeframe solution.
Manage access risk	The model allows participants to buy congestion relief in future, on an as needed basis. It promotes new financial constructs to manage congestion; longer term contracting promotes storage investment.	Model retains “winner takes all’ characteristics, with the “winners” able to sell congestion relief to the “losers”. Some stakeholders have expressed concern that the voluntary nature of the scheme may not result in sufficient congestion relief.
Effective wholesale competition	The CRM intends to provide a clear, transparent price signal for congestion relief services. The model seeks to make explicit, the ability for storage to provide congestion relief. It creates a market for system stability services; battery storage only needs to synchronise to the grid to provide relief rather than charging.	Potential risk that parties will not engage with CRM given complexity of multiple bidding arrangements. It will be necessary to design the CRM in a way that ensures it do not create new opportunities to distort competitive outcomes to maximise congestion relief payments.
Implementation considerations	Model aims to utilise existing market design and limits that are employed in the current energy and ancillary services markets (e.g. price bands, market price cap, market price floor, etc.)	The new market introduces potentially significant complexity and cost. Model may suffer from transaction and liquidity costs.
Support for jurisdictional schemes	The model supports REZs (and interconnector investments) by making sure that transmission infrastructure is utilised efficiently. It also creates incentives for storage and flexible load to locate within REZs and operate in ways that helps to alleviate congestion during periods of high VRE output.	

As a voluntary ancillary services market, the CRM does not ostensibly disrupt current due diligence processes for a project's investment decision. However, to the extent a project is affected by dispatch or price outcomes from the CRM optimisation, an investor may be passively affected if they choose not to actively participate. The CRM may also affect bidding behaviours in the energy market and 'force' generators to participate in the CRM to maintain or optimise individual outcomes. The CRM may encourage longer-term contracting between generators and storage providers for both parties to benefit from congestion outcomes and provide longer-term certainty of congestion relief costs / revenues for both parties' business cases.

There are several outstanding questions which could affect whether this model is workable or not. The ESB's preliminary view is that there is scope for the dispatch algorithm to be able to solve under the proposed CRM. Going forward, it will be important to reach a common view on how the model is intended to work. To date there have been differing interpretations, and some interpretations are workable and others are not. As we seek to clarify and resolve the outstanding issues, we will attempt to retain the features that make the CRM attractive to market participants while still focussing on designing a mechanism that focuses on the long-term interests of consumers.

Key questions

- What key attributes should the ESB seek to preserve as it works out how the dispatch algorithm should solve in the congestion relief market?
- What implementation costs are involved – both for AEMO and market participants?
- Should we adapt the model to remove the "winner takes all" characteristics implicit in the current specification?
- Should we adapt the model to reflect queue position in deciding which parties may sell congestion relief?
- What are the consequences of the congestion relief market in terms of bidding incentives?
- Should we adapt the model to preclude peaking generators from selling congestion relief when the RRP is low?

4 Next steps

The ESB invites comments from interested parties in response to this consultation paper by 10 June 2022. While stakeholders are invited to provide feedback on any issues raised in this paper, the key questions for consultation are summarised in Appendix A. Submissions will be published on the Energy Ministers' website, following a review for claims of confidentiality.

Submission information	
Submission close date	10 June 2022
Lodgement details	Email to: info@esb.org.au
Naming of submission document	[Company name] Response to transmission access reform Consultation Paper May 2022
Form of submission	Clearly indicate any confidentiality claims by noting "Confidential" in document name and in the body of the email.
Publication	Submissions will be published on the Energy Ministers website, following a review for claims of confidentiality.

The ESB intends to hold a webinar on the material covered in this paper on 26 May 2022, 2-4pm AEST. Interested parties are invited to register here.

In parallel, the ESB will continue to engage through a number of forums, including public webinars, stakeholder briefings, the Congestion Management Technical Working Group, jurisdictional advisory group, the Post 2025 advisory group and bilateral exchanges. Parties wishing to contact the ESB's congestion management project team should email info@esb.org.au.

The ESB will review submissions to this consultation paper in order to prepare draft recommendations for transmission access reform. Stakeholders will have an opportunity to comment and make submissions on the draft recommendations in Q3 2022. The next steps in the ESB's forward work program are set out below.

Milestone	Indicative timing
Public webinar on consultation paper	26 May 2022
Submissions due on consultation paper	10 June 2022
Draft recommendations for detailed design	September 2022
Public webinar on draft recommendations	September 2022
Submissions due	October 2022
Submit proposed rule change to Energy Ministers	Early December 2022

If Ministers adopt the ESB's recommendations, then the rule change proposal will be submitted to the AEMC for consideration. The timelines for implementing any reforms will be developed having regard to the urgency of the need for change, the scale of changes required, and the broader industry reform program.

Appendix A Summary of consultation questions

Model	Question
1. Congestion zones with connection fees (section 3.2)	1.1. What form of incentive should be used to influence generator location decisions? 1.1. What methodology should be used to calculate the efficient hosting capacity of the network for each zone? 1.2. How does this methodology reflect differences in the output profiles of different generator types? 1.3. How should the model treat multiple generators seeking access to the same part of the network? 1.4. Who should be responsible for administering various aspects of the framework? 1.5. How should connection fees be calculated? a. What is the correct balance between accuracy and simplicity/transparency? b. What should happen to revenue paid by generators?
2. Transmission queue (section 3.3)	2.1. How should a generator's queue position manifest in operational timeframes? 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. How does this methodology reflect differences in the output profiles of different generator types? 2.3. Who should be responsible for administering various aspects of the framework? 2.4. Can queue positions can be traded? 2.5. Should energy storage be subject to the same queuing terms as generators? 2.6. Should the framework encourage efficient retirement decisions for end-of-life generators and if so, how? 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?
3. Congestion management model (section 3.4)	3.1. What objective should we seek to achieve when selecting a metric to allocate rebates between generators? 3.2. Should we remove the "winner takes all" characteristics implicit in the current specification? 3.3. What are the consequences of the CMM in terms of bidding incentives? 3.4. Should we adapt the model to preclude out of merit order generators from receiving rebates when the RRP is low?
4. Congestion relief market (section 3.5)	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? 4.2. What implementation costs are involved - both for AEMO and market participants? 4.3. Should we adapt the model to remove the "winner takes all" characteristics implicit in the current specification? 4.4. Should we adapt the model to reflect queue position in deciding which parties may sell congestion relief? 4.5. What are the consequences of the congestion relief market in terms of bidding incentives? 4.6. Should we adapt the model to preclude peaking generators from selling congestion relief when the RRP is low?

Appendix B Current market design

This appendix describes the status quo to facilitate comparison with the alternative options.

B.1.1 High level design

The NEM has an open access regime which allows generators to connect to any part of the network at any time, subject to the network connection process with the relevant TNSP and AEMO. Once connected, the NEMDE determines which generators are dispatched for each dispatch interval.

The NEM is based on security constrained, optimised dispatch based on bids and offers through the NEMDE every 5 minutes. NEMDE is designed to meet demand at the lowest total system cost. Key determinants of dispatch include:

- bid price
- MLF
- coefficient (aka contribution factor, shift factor or participation factor)
- physical constraints including system security requirements.

A ‘snapshot’ of the conditions ahead of the five-minute dispatch period provides the starting point. The demand forecasting system provides a forecast for the demand at the end of the 5 minutes dispatch period and then optimises the dispatch of plant to meet that demand while ensuring the power system remains secure and the ramp rate advised for each relevant generating unit is not exceeded. In a single run, NEMDE dispatches all scheduled and semi-scheduled plant across the NEM, either operating or available to operate in the period. There are specific conditions under which two dispatch runs are required to determine optimal dispatch, such as when dispatch is over-constrained and prices breach limits.

Essential system services are also dispatched, with NEMDE co-optimising across energy and market ancillary services to deliver customers’ needs at the lowest cost. It is currently being modified to provide for a new fast frequency response service which will also be co-optimised with other services and energy. Other rule changes are being progressed to implement new ways to procure, schedule and price other essential system services.

Role of constraints

To ensure the dispatch delivers a secure power system, AEMO uses ‘Constraint Equations’ within NEMDE. Taken together, the many constraint equations used creates a mathematical model that reflects the underlying capability (or technical operating envelope) of the physical power system. There are over 10,000 constraints in the total library of constraint equations that AEMO uses, with up to 1,000 invoked at any time. TNSPs continue to provide updated limits and AEMO continues to create more constraint equations as new plant enters the system and as more is learnt through operating experience.

While thermal limits are usually easier to formulate and more straightforward than other limits such as transient stability, they still build to be quite complex in a meshed network. The resulting equations include a large number of specific generators or interconnectors, each of which has different contribution factors within the equation. The generators contribution factor in a constraint equation reflects its relative impact on the limitation.

The constraint equation or equations which are the most critical will vary as the pattern of load and dispatch change.

Bidding and security constrained, economic dispatch

All electricity markets seek to dispatch the lowest cost mix of plant to meet customer need subject to ensuring the system remains secure. Security constrained, economic dispatch in the NEM is given effect by the optimisation in NEMDE which has inputs of:

- the 'power balance constraint' i.e. supply must equal the forecast customer demand in each region at the end of the dispatch interval
- the constraint equations invoked at the time which define the secure operating envelope (and which include the generator coefficients)
- the bids and offers of generators and scheduled loads.

Bids and offers are scaled by their MLFs in the constraints which ensure supply matches demand to represent their supply to the regional reference node. The maximum allowed bid is $15,100 at the RRN and the minimum allowed bid is -$1,000 at the RRN.

Dispatch then is also dependent upon the bids and offers it receives from market participants and will be efficient where those bids and offers reflect costs. The cost of generation, supply from storage or reduction in demand from dispatchable load within a five-minute dispatch interval is not simple to determine. NEMDE is a linear optimiser and does not consider limitations on generators and loads which may have block limits such as a minimum operating level or a step-in load relief. The market participant needs to take account of those issues and reflect that in their bids and offers.

Bids with a common price

The regional design of the NEM leads to a special case where bids have no relation to costs. When a generator is behind a binding intra-regional constraint, they cannot set the price at the regional reference node. They then can bid any number without a risk that they have to supply to that number. This then provides the incentive for generators in such a position to bid the price floor to maximise their dispatch volume. Noting that the price floor is bid at the regional reference node, this can mean that a number of bids in the stack are at exactly the same level of -$1,000.

There can also be an issue when there is little spare capacity online and a number of generators, especially those with some uncontracted capacity, may bid the market price cap. Again, the maximum bid allowed is fixed at the regional reference node such that these bids would all be identical.

Role of tie-breaking

NEMDE is a linear programming solver which seeks to optimise the dispatch of all scheduled and semi-scheduled plant such that the overall as-bid cost is minimised and:

- the total generation dispatched matches customer demand
- all necessary market ancillary services are procured
- the system remains within the secure operating envelope defined by the constraint equations invoked at the time.

It is possible that two or more separate bids at same price are the marginal supply to the market. NEMDE deems two bids or offers in the same region are price-tied if their prices (adjusted by their MLFs) are within 10^{-6} of one another. In NEMDE tie-breaking is only enforced for energy bids and offers, not for the FCAS offers. Tied bids for blocks of energy are then dispatched in proportion to the MW sizes of the respective bands.

Under normal bidding, it would be unlikely that two blocks on the margin of being dispatched are bid by different parties at exactly the same price. However, this is not the case where parties are bidding to the price floor or the market price cap. In those cases, they would both be bidding the same price at the regional reference node. In recent years there have been large volumes of energy in a region bid in this way such that those could constitute tied blocks which were marginal to dispatch. Tie-breaking is, therefore, more likely than expected when the market was designed.

In practice, tie-breaking occurs very infrequently. Where there are network constraints binding, bids of the same price will not be tied where they have different contribution factors in the constraint equation. The dispatch algorithm will try to dispatch the lowest cost generation to meet customer demand subject to the security constraints. When a network constraint is binding it is restricting access to lower cost supply. The dispatch algorithm will try to maximise access and so will preferentially dispatch those generators which have a lower contribution factor i.e. lower impact on the constraint.

Winner takes all outcome

Where blocks of energy bid by different generators have the same price, that preferential dispatch will apply even if the contribution factors of two generators only vary by a very small amount. There are constraints where the difference in contribution factors might only differ in the 4th decimal place but, when binding, the party with the lower contribution factor will be preferred. This is what is sometimes referred to as the 'winner takes all' artifact of the current market arrangements.

Network congestion within a region (or intra-regional congestion) is the most likely driver of bidding to the price floor and in such cases that would not be likely to lead to a need for tie-breaking other than for parties located close to each other, on the same radial line and having similar technical characteristics.

Table 14 Core features of status quo in investment timeframe

Feature	Current market design
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	The current market design does not include design features that seek to align generation investment with available transmission. In the absence of signals arising from an access regime, investors respond to other aspects of the market framework such as connections bottlenecks, MLFs, and costs associated with system strength remediation.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	The current market design does not include design features that seek to align generation investment with available transmission. Instead, investors invest at their own risk.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	Generators may connect to the grid at any point (subject to meeting technical requirements).
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	Generators receive no assurance that the transmission network will be capable of transporting their output to load centres. New connections may substantially erode the access of existing generators.
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	As the access regime does not protect the access of existing generators, it supports efficient retirement decisions for end-of-life generators. It may, however, encourage inefficient new

Feature	Current market design
	entry that displaces equally competitive existing generators (if the new entrant has a better generator coefficient).
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	Generators do not pay for shared transmission and have no rights over the shared transmission system. They have no incentive to fund incremental augmentations that enhance hosting capacity, since any such investments could be co-opted by their competitors.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	As the current market design does not reflect the cost of congestion, two-way technologies are not incentivised to locate in places where they can provide congestion relief.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model is incompatible with REZs because it is not possible to confer meaningful advantages on REZ generators. Generators will be better off to free ride on the REZ by connecting outside the REZ without having to participate in a tender process.

Table 15 Core features of status quo in operational timeframe

Feature	Current market design
Efficient dispatch outcomes How does the model dispatch the cheapest available combination of resources to securely meet demand?	Generators affected by constraints are incentivised to maximise their share of the limited transmission capacity by engaging in ‘race to the floor’ bidding behaviour. This does not necessarily reflect the cheapest available combination of resources.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to help to alleviate congestion?	The model does not create these incentives. Indeed, two-way technologies may be incentivised to make congestion worse if the price is high.
Managing inter-regional flows How does the model ensure efficient use of the transmission system when inter regional flows are affected by congestion?	Participants affected by congestion in their home region will be dispatched if their bid is lower than the RRP in an adjacent region, however they receive the RRP in their home region. If RRP(home) exceeds RRP(adjacent) a settlement shortfall arises. If the shortfall exceeds $200,000, AEMO clamps the interconnector.
Allocating the value arising from regional pricing How does the model allocate the value arising from the use of regional pricing?	The value accrues to the participant that is dispatched, which is subject to winner takes all outcomes.

The ESB’s assessment of this model is set out in Chapter 2.

Appendix C Investment timeframes

This appendix describes and outlines the ESB's assessment of the CMM REZ adaptation, physical access rights via locational connection fees, the REZ connection fee model and shaped marginal loss factors.

C.1 CMM – REZ adaptation

This model has not been shortlisted for consideration. In preference, the ESB has put forward the two short-listed models above; congestion zones with connection fees model and transmission queue. Both can adapt with jurisdictional schemes more readily and in a more flexible way, minimising costs to consumers. Refer to section 3.2. This change has been made in response to stakeholder concerns that exposing generators to congestion charges, without the benefit of a rebate, could inefficiently stifle new entry outside REZs.

This change enables the ESB to put forward the CMM with universal rebates model in operational timeframes. The ESB observes that this variant of the CMM shares a number of features in common with the CRM. Refer to section 3.4.

C.1.1 High level design

The CMM-REZ model can be thought of as having two limbs – the CMM limb and the REZ limb:

- The CMM limb relates to the settlement algebra and the dual mechanism of congestion charges and congestion rebates. This limb is discussed in section 3.4.
- The REZ limb relates to who is eligible to receive the rebates. By being selective about who receives rebates, we create a tool to influence generator location decisions. This limb is discussed in this section.

Under the REZ limb of the CMM-REZ, eligible scheduled and semi-scheduled generators would receive a congestion rebate, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges in that dispatch interval. The size of the rebate would be determined in accordance with a pre-determined allocation metric, such as a generator's availability and participation factor in the binding constraints in comparison to other generators' availabilities and participation factors.

Incumbent market participants would automatically receive a rebate to compensate them for the financial impact of the introduction of the congestion change. New market participants who connect within REZs would be entitled to participate in a process to purchase access to rebates, most likely through a competitive process such as an auction. This may be an auction separate to the jurisdictional REZ schemes, or in effect be a part of the processes currently being developed by jurisdictions which not only allocates access to rebates, but other rights such as financial contracts for energy.

Generators outside of a REZ, and potentially those within (but who are connecting after the initial process to the fill the REZ)[29], would be entitled to connect without rebates, which would then expose them, unhedged, to the congestion charge. Of course, in some areas of the grid, the congestion charge would be expected to be low, because there is ample spare capacity both now and forecast in the future. In making this decision, the cost of congestion is borne directly and fully by them. Market

29 The ESB envisages that generators could connect to a REZ after the initial tender process to establish/fill the REZ, however, in this case, they would not receive congestion rebates.

participants who have purchased rebates via the REZ process would be hedged against the cost of congestion caused by the non-rebate holding market participant, via a larger rebate pool being divided between the same number of rebate-holding market participants.

The collective payout of the rebates is equal to the revenue from the congestion charges. This means that the more market participants that hold an entitlement to receive rebates, the lower their individual payouts will be on average. In turn this means that the rebates will be less good congestion risk management tools for their holders.

If this model was implemented, it would be necessary to make a trade-off along a spectrum between:

- making the rebates abundantly and widely available, so that many prospective generators can have relatively low-quality congestion risk management tools, and
- making the rebates available in limited numbers at specific areas of the network where there is network capacity, so that generators connecting early and in those areas have high quality congestion management tools.

Table 16 Core features of CMM-REZ adaptation

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	The locational signal is in the form of a congestion rebate. Rebates are available to incumbents and generators that connect within a REZ.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	Rebates are made available for locations identified via an enhanced transmission planning framework to develop REZs. The rebates allocation is aligned to AEMO’s ISP including the development of REZs.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	Rebates are made available via some form of REZ tender process.
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	Incumbent generators receive rebates. The definition of incumbents will form part of future detailed design work.
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	The model allows for design options regarding the grandfathering of rebates to incumbent generators. For example, after a pre-determined period, incumbent generators could be excluded for the purposes of deciding where new rebates are available. Incumbents would still receive rebates but the rebate revenue would be distilled with new connecting generators.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	The model allows for design options where rebates are made available above planned levels to parties that agree to fund measures that increase hosting capacity.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to	Demand-side and two-way technologies benefit from lower prices in the presence of congestion. For batteries, this means

Feature	Model proposal
locate where they provide the most benefits to the system?	they can access greater price spreads by storing energy until the congestion has passed.
Support for jurisdictional schemes	Supports jurisdictional schemes by making congestion rebates available to REZ generators. The access of REZ generators would be protected from the impact of new connecting generators outside the REZ due to the impact of the congestion charge.

C.1.2 Assessment

The CMM-REZ model would automatically assign rebates to incumbent market participants to compensate them for the financial impact of the introduction of the congestion charge. The rebate would be designed to make market participants broadly financially indifferent to the introduction of the congestion management charge compared to the status quo. Collective revenue received from the congestion management charge would be allocated to rebate holders.

The selective availability of congestion rebates is a tool to incentivise generators to connect in locations with spare transmission capacity available such as REZs. The CMM-REZ model will enable participants who connect in a REZ to purchase rebates, most likely through a competitive auction.

The model supports and strengthens the REZ framework by rewarding generators who locate in the REZs with access to better congestion risk management tools. Outside REZs, generators are incentivised to manage congestion risk by connecting in uncongested areas. By limiting the number of rebates available to these areas, holders would receive greater certainty relating to the impact of congestion on their profits.

Generators that connect outside REZs would be exposed, unhedged, to the congestion charge. This feature of the model strengthens the incentives on new generators to connect in areas of the network with the capacity to support their output and minimise their impact on existing congestion.

A number of generator and investor representatives expressed concern about this aspect of the model. For instance, Origin, Iberdrola, and AEC suggested that the CMM-REZ could act to reduce network utilisation beneath efficient levels.[30] This would occur if investors were unwilling to take on congestion risk in the form of LMPs. We agree that this could be an issue with the model.

Accordingly, the ESB proposes to move away from the investment timeframe elements of the CMM-REZ, and instead focus on alternative mechanisms to deliver coordinated transmission and generation investment.

The REZ adaptation limb of the CMM-REZ is focussed on creating incentives in investment timeframes. This impact of the CMM in operational timeframes is discussed in section 3.4.

30 Submissions to the project initiation paper are available here: https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/transmission/congestion-management-mechanism

Table 17 Assessment of CMM-REZ adaptation

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	Generators are incentivised to locate in REZs. Loads are encouraged to make efficient investment decisions and locate behind constraints where they may benefit from lower local marginal pricing. Assuming that rebates to new entrants are allocated via a tender process, rebates would be awarded to parties who value it the most. Lower cost generators would, in theory, be willing to pay more than higher cost generators.	The signals provided by the availability of rebates are dependent on accurate forecasts and assumes that the REZs are in the best locations i.e. it is open to central error. However, the ESB notes that the consequence of not receiving a rebate is that the generator receives the local price when congestion occurs, which is the efficient price signal. We have heard from investor stakeholders that this is not an acceptable risk under access reform.
Appropriate allocation of risk	Model allows for coordination between AEMO/TNSP/REZ coordinators to identify efficient connection locations as part of long-term network planning. For new entrants ineligible for rebates, the party causing congestion is exposed to the marginal cost of congestion. Assuming that rebates to new entrants are allocated via a tender process, participants will form a view on the value of rebates and proceeds from the tender can be returned to consumers.	Customers bear the risk of misdirected investment due to central error identifying location of REZs. Nodal pricing faced by non-REZ generators may not allow deep and liquid hedge markets to manage volatility in local price outcomes.
Manage access risk	Improved revenue confidence for rebate holders that receive payments designed to broadly replicate the RRP. Incumbents benefit from grandfathered rights.	New generators do not have tools to manage congestion risk in non-REZ locations (beyond the information available at the point of financial close).
Effective wholesale competition	Notice of closure signals indicate available capacity to new developers. Depending on transfer arrangements for rebates, new entrants could share in the rebates available to end-of-life generators.	It would be necessary to design this model in a way that ensures that the rebates do not incentivise incumbent thermal generation to stay in the market even when it is not contributing value.
Implementation considerations	The model allows for close alignment with the intent of jurisdictional schemes to incentivise generation investment in REZs.	Model may trigger re-opening of contracts and PPAs. The allocation of rebates has potential to be complex and contentious.

C.2 Physical access rights via locational connection fees

Model options proposing physical access rights have not been shortlisted for consideration on grounds that they are likely to create barriers to new entry and have the potential to result in inefficient transmission investment. However, an adapted version of the connection fees model has been shortlisted in section 3.2.

C.2.1 High level design

The locational connection fee model[31] is conceived as a "do low harm" requirement for new generators seeking to connect to the transmission network. An application to connect to existing (or proposed) network infrastructure would include the following key steps.

A new connecting generator must undertake modelling (in consultation with the TNSP) to identify all scenarios where the proponent could 'do harm' to existing generators.

The proponent would work with the TNSP to assess the physical network augmentation, generation asset capabilities and/or operational behaviours necessary to address these impacts, such as being constrained off or the implementation of special control schemes.

If it is determined that the new connection would increase the level of congestion, and the proponent wants firmer network access, the TNSP would calculate the locational connection fee, being the cost of undertaking any physical augmentation on the basis of it being a regulated or negotiated network asset paid for by the connecting generator. This calculation would consider the level of network access sought new asset's capabilities and agreed operational behaviours.

Once the financial terms of the connection agreement are agreed, the TNSP would complete the augmentation (or facilitate any operational control schemes) and the generator would be approved for connection.

Table 18 Core features of locational connection fees model

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	New connecting generators are required to "do low harm" to pre-existing generators. New entrants are incentivised to locate in areas of low forecast network congestion to minimise their locational connection fees and/or their operational behaviours.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	The model applies to the full NEM including actionable ISP projects and network projects to facilitate REZ's. The "do low harm" assessment conducted during the connection process determines the connection cost or agreement to be operationally constrained off and would be based on 'system normal' conditions. In addition, a revised RIT-T approach for shared network projects allocates costs to customers, existing generators and new entrants in proportion to the benefits they receive.
Approach to managing new connections	A queuing mechanism determines the order in which "harm" is assessed.

31 Model design is based on the proposal submitted by Shell Energy, Shell Energy Response to P2025 Market Design Consultation Paper, initially submitted June 2021 and re-submitted January 2022.

Feature	Model proposal
How does the model deal with different proponents seeking connection at different times?	
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	Incumbent generators have already connected and hence do not pay connection fees. Incumbent generators have confidence that their access will not be materially constrained in future by new entrants.
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	A new entrant could enter commercial contracts under which existing generators could agree to being 'harmed' under specific circumstances. Retiring generators that have chosen to contribute to network augmentation or have been required to contribute may sell their access rights to new generators. Where retiring generators have not contributed, their existing network capability would return to the pool.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	New entrants can negotiate with the TNSP on whether they accept a lower level of firmness or fund the costs of physical augmentation.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	Generators will assess congestion relief solutions to identify the most effective / least cost to minimise locational connection fees. It requires measures to ensure that parties behave as intended in operational timeframes.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	REZ generators are protected against new connections outside of the REZ given rules to "do low harm" for generators planned inside the REZ (i.e. do low harm accounts for planned as well as existing generators in the REZ).

C.2.2 Assessment

In investment timeframes, the access regime is intended to give:

- confidence to all generators that their transmission access will not be materially compromised by new entrants
- clarity to new entrants regarding their locational costs and certainty associated with their connections.

The model does not change the market design in operational timeframes. However, by establishing a framework that builds out transmission to achieve pre-determined levels of congestion, the model is likely to impact the frequency and extent of congestion events.

Table 19 Assessment of locational connection fees model

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	The model provides strong locational signals; where there is spare transmission network capacity, new entrants will benefit from lower connection fees. Projects will be disincentivised from locating in weak grid areas.	Process relies heavily on the accuracy of the modelling. It has potential to stifle investment given the lumpiness of transmission investment and the need for deep network reinforcement. Could lead to uncoordinated, inefficient transmission investment if the "do low harm" requires investment in physical assets that are rarely used.
Appropriate allocation of risk	The model encourages new entrants to engage with the NSP and look for innovations that (1) avoid impacting others (2) efficiently invest in network without charging customers. Costs of new-build transmission infrastructure is allocated between consumers and generators to reflect their relative benefits.	Model places the onus on TNSPs to correctly assess "do low harm" and specify remediation works– they make be incentivised to take a conservative approach.
Manage access risk	Generators can be confident that their transmission access won't be materially compromised by new entrants.	If the modelling is inaccurate, participants who paid connections fees may have their access impinged on, or inefficient changes to further connections may be required.
Effective wholesale competition	There is potential to trade connection asset property rights to deal with lumpy oversized transmission investment.	The model allocates physical access rights to incumbent generators, even though they were not required to pay for these rights when they connected. Lumpy transmission investment means that new entrants face the risk of being the "straw that broke the camel's back" and bearing cumulative transmission upgrade costs caused by others.
Implementation considerations	The model can be designed to protect REZ generators in accordance with jurisdictional schemes.	The increased complexity of the connection assessment may cause delays to the connection process. There is significant complexity in the upfront assessment and modelling to determine harm by AEMO/TNSP/REZ coordinators. If new entrants choose to modify their operational behaviours and accept self-curtailment to avoid locational fees, the resulting runback schemes can face technical limits (lesson learned in WA).

The ESB does not consider such a physical access model is feasible because of the following issues:

- **Barriers to entry:** Given the lumpiness of transmission investment, physical access regimes pose substantial barriers to entry once the capacity of the network has been allocated to generators. This barrier is somewhat of a necessity to a physical access regime to ensure that the existing rights are not harmed by further connections. In Western Australia, attempts to mitigate these barriers - by establishing a framework whereby groups of new entrants can share the cost of transmission upgrades – have not been successful in promulgating new transmission build.
- **Inefficient transmission investment:** To assure a level of physical access to generators, the network must be "overbuilt" to reduce the potential for constraints to bind and curtail generators' dispatch, creating costs for consumers.
- **Slow/complex connections process:** A second way to ensure the firmness of physical access rights is to include the need to maintain these rights in the connections process. This can either mean limiting or banning connections, introducing connection fees for network augmentation, or introducing complicated runback schemes to ensure existing physical rights are not impinged upon.

While there may be some approaches to deal with the problems raised above, these would move it away from a physical access regime. For example, in relation to the introduction of network fees, problems have historically occurred when connecting parties had to pay to remedy the marginal impact of their connection. In practice, this means that the cost of connecting is very low until the capacity of the network is reached. At this point, the cost of connection can increase dramatically, depending on the size of the network augmentation necessary to ensure the impact of the connection does not harm existing generators.

Another option is developing an administratively determined connection fee that can better reflect the long-run cost of a generator connecting to a certain part of the network. This is similar to the congestion zones with connection fees model discussed earlier.

A second potential solution could be to implement a financial compensation mechanism as opposed to a physical mechanism. This would mean that new connecting generators who may harm the access of existing generators could enter into an agreement to financially compensate the existing generators for any periods where they are constrained off due to the new connection.

Previous access reviews have concluded that a pure financial compensation regime (with no physical access) is more efficient than attempts to integrate a financial compensation mechanism with a physical access regime. The CMM is, in effect, a financial compensation regime.

C.3 REZ cost allocation model

The ESB notes that this model was not put forward by its original proponents, rather it was recommended for further consideration by another stakeholder. The model option has not been shortlisted on grounds that it focuses on establishing a framework for investing in transmission, and allocating the costs, rather than improving the way the NEM manages congestion.

C.3.1 High level design

The model[32] proposes to alter rules on cost allocations and financing for transmission assets so that:

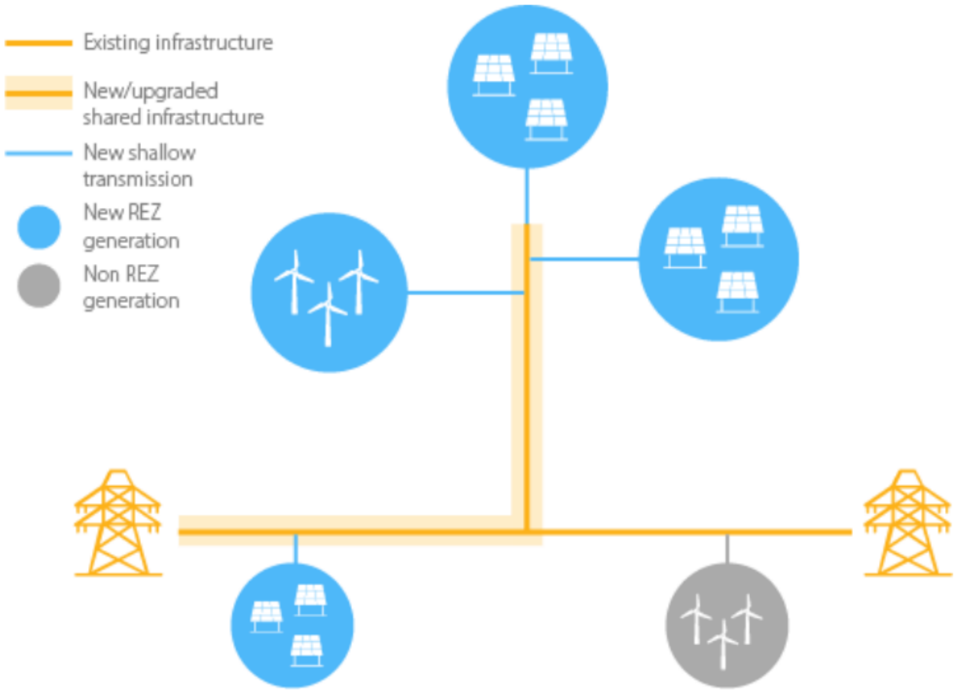
- capital costs of shared infrastructure, including augmentations to the existing network, can be recovered from connecting generators (rather than just consumers)
- shared infrastructure can be financed by a contestable investor, such as government, the TNSP or some other entity (rather than just through a TNSP).

Transmission investment is separated into two portions:

- cost recovery via regulated revenue (status quo)
- contestable works recovered through generator connection charges (new carve out).

The figure below illustrates that the new rules would apply to parties within a REZ development.

Figure 14 Classification of a network in a REZ



Source: Public Interest Advocacy Centre (PIAC), PIAC Response to P2025 Market Design Consultation Paper, June 2021, p.17

32 Model design is based on the proposal submitted by the Public Interest Advocacy Centre (PIAC), PIAC Response to P2025 Market Design Consultation Paper, June 2021

Table 20 Core features of the REZ cost allocation model

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	REZ transmission capex is recovered from both generators and consumers, rather than just consumers. Costs for transmission assets are shared so they can be partially recovered from connecting generators and other benefiting parties. The model intends to realign the costs to the beneficiaries, lower the consumer benefit threshold and accelerate transmission investment decisions.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	Feasible prospective REZs, including any necessary supporting network investments, are identified through the existing ISP process by AEMO, industry or government.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	Generators are charged a fixed rate ($/MVA) to access prescribed capacity. The rate paid by generators would increase with time according to a speculative rate of return escalation factor.
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	The model can be adapted to share transmission upgrade costs with new connecting and pre-existing generators in proportion to their relative benefits.
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	This is not a model feature.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	If the level of interest in the REZ exceeds the prescribed 'efficient' capacity level determined, the transmission investor may fund this additional capacity and negotiate with generators as unregulated revenue.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	No additional signals for congestion relief. The RIT-T process must consider non-network solutions as part of its credible options assessment.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	If applied in conjunction with an access reform model, this model could provide a framework for investing in REZ transmission assets and allocating the costs.

C.3.2 Assessment

The connecting fee is designed to coordinate generation and transmission investment decisions. REZ generators are required to internalise some of the costs of REZ transmission investment. The connecting fee provides clarity to new entrants regarding their locational costs. REZ coordinators are responsible for determining the level of certainty associated with their connections (in terms of future congestion and curtailment).

Table 21 Assessment of the REZ cost allocation fee model

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	The model intends to accelerate REZ transmission investment by lowering the consumer benefit threshold and allocating costs to generators.	Risk that investment is incentivised in non-REZ locations where generators are not required to pay connecting fee.
Efficient market outcomes – dispatch	n/a	n/a
Appropriate allocation of risk	The model encourages new entrants to internalise some costs of their investment decisions on existing generators. Costs of new-build transmission infrastructure are allocated between consumers and generators to reflect their relative benefits.	Where the TNSP makes upgrades and allocates cost to new connecting assets, the TNSP (or government underwriter) holds some stranded asset risk if new entrant generation is less than-expected. The upside is that the stranded asset risk could incentivise TNSPs to control costs.
Manage access risk	The model provides investors with clarity on upfront locational costs. Access risk is managed according to the terms of the REZ development e.g. generators may be guaranteed a maximum level of curtailment within their node.	REZ generators may not be protected against new connections outside of the REZ that impinge on their curtailment risk.
Effective wholesale competition	Additional costs associated with the transmission connection of new entrants are commensurate with the benefits received.	No additional signals for congestion relief beyond the existing RIT-T process that considers non-network solutions as part of its credible options assessment.
Implementation considerations	The model can be designed to protect REZ generators in accordance with jurisdictional schemes.	The model creates an inconsistency between RIT-T cost allocation procedures for REZ and non-REZ zones. Complexity introduced for regulatory oversight of TNSPs revenues.

The model has not been shortlisted given its focus on cost allocation between utility-scale generation and consumers, rather than explicitly dealing with congestion. While transmission investment is an essential component of the task of delivering the energy transition, it does not replace the need for transmission access reform.

REZ models that seek to allocate some or all transmission costs to generators require access reform to work. A REZ model that creates an “access island” within the meshed network will experience challenges due to the physics of electricity. Further, generators need their power to be transported from the REZ to load to earn revenue, which means that the business models of REZ generators could be undermined by developments outside the REZ. Given these uncertainties, the ESB is not convinced that generators would be eager to fund REZ transmission assets if they can connect for free outside the REZ. This conclusion is consistent with the findings of the AEMC in the COGATI review.[33]

The ESB has not attempted to assess the model in terms of its intended purpose – namely as a framework for investing in transmission and allocating the costs. Rather, we note that access reform is a pre-requisite for other reforms that allocate transmission costs to generators.

33 AEMC Renewable Energy Zones Discussion Paper, Appendix A.3.

C.4 Shaped marginal loss factors

The model option has not been shortlisted for consideration on grounds that it does not directly address congestion issues. However, it may have merit in terms of improving the MLF framework. This would need to be considered as part of a separate reform process such as a rule change proposal.

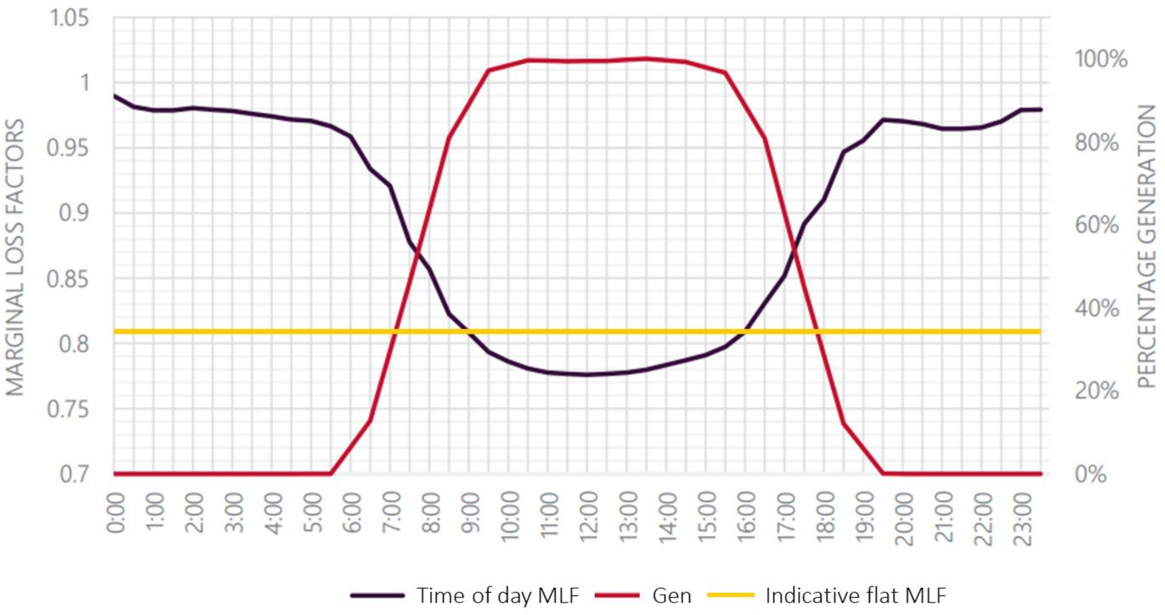
C.4.1 High level design

The model proposes to apply MLFs as a proxy to solve for congestion issues. It is intended as contributory solution as part of a potential package of reforms rather than a silver bullet.

MLFs reflect the impact of electricity losses along the network. They are applied to market settlements in the NEM and hence affect generator revenues. They represent electricity losses along the transmission network between a connection point and the RRN. MLFs are affected by the location of new generation projects and load developments on the transmission and distribution network. Losses increase as more generation connects in locations that are distant from load centres.

AEMO publishes MLFs by 1 April of each year for the upcoming financial year. The loss factor is fixed for the given financial year. The flat MLF differs from actual losses incurred across the day. Figure 15 illustrates for a solar farm how the flat MLF is lower than actual losses in shoulder periods, and higher than actual losses over the middle of the day.

Figure 15 Time of day average MLF and percentage generation



Source: CS Energy, as adapted from AEMO's Regions and Marginal Loss Factors: FY 2020-21, p.65

The model proposes to amend the MLF methodology as follows:

A fixed shape time of day MLF would replace the single annual generation weighted MLF and would reflect the changes in physical losses of different generation units in different parts of the network over the course of the day.

The MLF of a new project would reflect its marginal contribution of energy beyond that of incumbent generation in that network location i.e. new entrants in heavily populated parts of the network would need to assess whether their project is commercial given its expected marginal energy contribution in that location.

Table 22 Core features of shaped marginal loss factors

Feature	Model proposal
Nature of incentive How does the model incentivise efficient investment decisions/ disincentivise inefficient investment decisions?	The mechanism exposes participants to an MLF that more accurately represents actual losses on the network over the course of the day.
Identifying efficient connection locations How does the model determine which parts of the network should be subject to incentives/ disincentives to connect?	Proponents of projects in heavily populated parts of the network would assess whether their project is commercial given its expected marginal energy contribution. A low true MLF would dissuade new projects from connecting in heavily populated parts of the network. The time-of-day signal would also provide a signal of what technologies may be better suited to particular locations.
Approach to managing new connections How does the model deal with different proponents seeking connection at different times?	No change to the connections process is proposed.
Treatment of pre-existing generators How does the model treat existing generators? What is the balance between new entrants and incumbents?	The model states that new generators would face the true MLF. This will maintain the relativity between incumbent MLFs and new plant MLFs over time.
Efficient retirement decisions How does the model framework encourage efficient retirement decisions for end-of-life generators?	No change to the status quo proposed.
Maximising hosting capacity of available transmission How does the model maximise the potential hosting capacity of the network by encouraging investments that enhance hosting capacity?	Participants will be encouraged to minimise their impact on transmission losses.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to locate where they provide the most benefits to the system?	Charge and discharge functions of storage would have fixed-shape time-of-day MLFs that reflect the relative contribution of each over the course of the day. High coincident generation in a local area relative to load would normally be expected to result in low MLFs for storage in that area, which will enable it to charge for less than the RRP, and discharge at times when firm generation is needed.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model can be applied in conjunction with State government REZ schemes. It increases the value available to generators whose output profiles are less correlated with other generators that share the same transmission assets, leading to improved utilisation of REZ assets.

C.4.2 Assessment

Many respondents to the project initiation document[34] (including the Clean Energy Council, Snowy Hydro, Origin, NEOEN) have suggested that locational signals already exist in the NEM in the form of marginal loss factors (MLFs). The shaped MLF model seeks to improve the accuracy of these signals by establishing a "true MLF" that is intended to achieve the following objectives:

- A true MLF would dissuade new projects from connecting in heavily populated parts of the network.
- The time-of-day profile would reinforce what technologies may be better suited to a particular location.

This model has the potential to provide more accurate locational signals in terms of losses. However, the focus of this review is to provide locational signals with respect to congestion.

Shaped MLFs at certain times of day would encourage batteries to focus their output at times when they have more favourable MLFs. The extent to which this is effective in managing congestion depends on the extent to which MLFs are correlated with congestion.The ESB recognises that in developing this proposal, CS Energy abided by the ESB's terms as set out in the project initiation document: namely, that the model sought to address the access reform objectives and has not been proposed before. These terms significantly narrowed the range of potential solutions.

Table 23 Assessment of shaped marginal loss factors

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	The model proposal provides a more accurate reflection of power system losses over a daily period.	Congestion and losses may be correlated but they are not caused by the same physical drivers. The fixed shape MLF would not account for seasonal variation. It offers a halfway house before introducing dynamic MLFs (which have already been considered in an AEMC review).
Efficient market outcomes – dispatch	n/a	n/a
Appropriate allocation of risk	By assigning a true MLF to new projects, the cost of the new entrant's impact on transmission losses would be borne by the causer in perpetuity. The MLF could increase in response to changes in generation capacity, generation, load or network capacity in relevant parts of the network, but the relativity between incumbent generation and the newer entrant would be maintained so as not to adversely affect incumbents' transmission losses.	Relies on centralised modelling of the true MLF.

34 Submissions to the project initiation paper are available here: https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/transmission/congestion-management-mechanism

Assessment criteria	Pros	Cons
Manage access risk	Connecting generators (and their investors) are familiar with forecasting and monitoring MLF risk.	Fixed shaped MLFs may provide an indirect signal of congestion risk. Losses and congestion are not equivalent and when transmission is congested, the MLF sensitivity disappears (which has occurred in central and northern QLD).
Effective wholesale competition	In theory, the model may encourage shared investment in load or network capacity to lift the MLF for generators in a congested location.	Shared investments have been difficult to finance given the competition between generating assets and the staggered times at which they achieve financial close and complete construction. Fixed shaped MLFs may have a significant effect on the business case of solar farms. The model is likely to give rise to questions with respect to grandfathering and the consequent trade-offs between the interests of incumbents and new entrants.
Implementation considerations	The proposed model would not impede different jurisdictional initiatives and policies e.g. REZ schemes.	It would be necessary to establish a framework to calculate time of day MLFs and feed this information into the dispatch algorithm.

MLFs signal a different electrical phenomenon to congestion and a representation of the network at a particular point in time. MLFs are not designed to measure or reflect congestion. Rather, MLFs are used to adjust electricity prices to reflect the marginal cost of energy lost in transporting electricity across networks. This does not reflect the impact that electricity generated at a particular point on the network has on congestion across the network. Losses can be thought of as goods lost in transit, versus congestion which can be thought of as traffic jams (noting that congestion does compound losses). Analysis by the ESB suggests that in their current form, MLFs and congestion are weakly correlated.[35] Investment decisions that are guided by MLFs may still be poorly located from a congestion perspective. MLFs are also only calculated annually and represent the state of the network at that point in time.

. That said, the shaped MLF model may have merit in terms of improving the MLF framework. However, we consider that this proposal should be considered via a different process to maintain our focus on congestion.

Further analysis is required to assess whether this proposal unduly disadvantages technologies that have a regular diurnal profile. Other technologies may have output that is highly correlated between generators of the same type, and hence have a similar impact on losses. However, if these generators are less consistent in terms of the time of day that they generate, they may be less impacted by shaped MLFs due to the impact of averaging.

35 Energy Security Board, Post 2025 Market Design Options – A paper for consultation Part B, p. 84. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf

Appendix D Operational timeframes

This appendix describes and outlines the ESB's assessment of revised tie breaker rules and dual price floors.

D.1 Revised tie-breaker rules

The model option has not been shortlisted for consideration although the queue mechanism has been adopted in section 3.3.

D.1.1 High level design

The model proposes a change to current tie-breaker rules. In the event of a binding constraint, generators with tied bids would be differentiated based on:[36]

- cost
- commissioning date (if bids remain tied after the cost assessment).

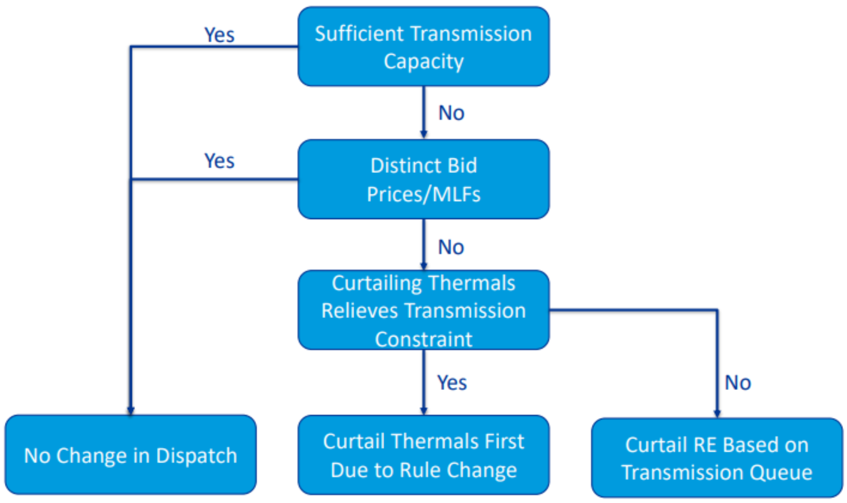
This sequencing would allow REZ foundational developers to be dispatched ahead of late entrants.

A simplified version of this rule would differentiate based on:[37]

- renewable generators and battery storage to be dispatched in preference to thermal
- commissioning date which determines a queue system (as per section 3.3).

Figure 16 shows the interaction in the dispatch order between the simplified rule change and the transmission queue.

Figure 16 Interaction of the rule change and transmission queue



Source: Castalia Ltd, Transmission access reform_Report to Clean Energy Investor Group (CEIG) p.51, February 2022

36 Model design is based on the proposal submitted by EnergyAustralia, EnergyAustralia Response to the Project Initiation Paper, Congestion Management Model, January 2022

37 Model design is based on the proposal submitted by the Clean Energy Investor Group (CEIG) Report on Transmission Access Reform, February 2022.

Table 24 Core features of the revised tie breaker rules model

Feature	Model proposal
Efficient dispatch outcomes How does the model dispatch the cheapest available combination of resources to securely meet demand?	Lower cost generators (renewable and energy storage) are dispatched before higher cost generators (thermal) when both have bid the same price and transmission capacity is constrained. When the constraint applies to generators with equal marginal cost (e.g. renewable generators), dispatch priority is based on commissioning date/queue order.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to help to alleviate congestion?	Requires further consideration.
Managing inter-regional flows How does the model ensure efficient use of the transmission system when inter regional flows are affected by congestion?	Requires further consideration.[38]
Allocating the value arising from regional pricing How does the model allocate the value arising from the use of regional pricing?	Dispatched generators receive RRP. Dispatch determined in accordance with amended tie breaker rules.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model can be applied in conjunction with State government REZ schemes because REZ schemes are focussed on investment timeframes rather the assets' operations.

D.1.2 Assessment

Dispatching generators with equal marginal cost based on their commissioning date would, in theory, create an incentive for generators to avoid congested parts of the network. However, the proposed tie-breaker rules are solving for an event that is unlikely to occur (both in the current and future energy system as the generation mix evolves).

As a result, the tie-breaker rules do not provide a strong locational signal to solve for congestion issues. The 'winner takes all' artifact of the current system would remain.

The proposed model differentiates bids in a network constraint based on regulatory assumed costs or a binary (thermal / non-thermal) in order to achieve efficient dispatch. Generators and storage with lower short-run marginal costs would be dispatched first. A second measure of commissioning date is applied as a final differentiating factor. However, the tie-breaker rules would apply after the dispatch engine has already considered price, MLF and contribution factors.

When network constraints bind, bids of the same price will not be tied where they have different contribution factors in the constraint equation. The dispatch algorithm will try to dispatch the lowest cost generation to meet customer demand subject to the security constraints. The dispatch algorithm will try to maximise access and so will preferentially dispatch those generators which have a lower

38 EnergyAustralia's submission included a separate proposal for dealing with interconnectors which would change the way that interconnectors are treated in the constraint formulation guidelines.

contribution factor i.e. a lower impact on the constraint. That preferential dispatch will apply even if the contribution factors of two generators only vary by a very small amount.

Tie-break events are unlikely given the precision of contribution factors.

Table 25 Assessment of the revised tie breaker rules model

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	n/a	n/a
Efficient market outcomes – dispatch	The intent of the model is to prevent generators with higher underlying costs from being dispatched and removes the incentive for thermal generators to bid in a disorderly manner.	Tie breaker rules rarely take effect due to the impact of participation factors. The model relies on regulatory rules, rather than market offers, to decide dispatch order in the face of congestion. It may entrench disorderly race-to-the floor bidding between non-thermal generators and does not promote efficient dispatch via NEMDE.
Appropriate allocation of risk	New entrants bear more risk through a higher place in the queue which preserves the incumbency advantage; new entrants causing congestion incur the costs of curtailment.	Consumers face the costs of inefficient dispatch. Congestion rent stays with generators.
Manage access risk	The model seeks to manage access risk through changes to the tie-breaker rules which, other things being equal, would dispatch generators in order of commissioning date.	Tie-breaker rules rarely determine dispatch outcomes. No apparent encouragement for storage/load to participate more behind constraints and alleviate congestion.
Effective wholesale competition	n/a	The model does not lead to effective competition. It creates an incumbency benefit merely by being an older asset which is unlikely to lead to an efficient portfolio for dispatch. For this reason, the model is not considered to promote the long-term interests of consumers.
Implementation considerations	Rule change supplants existing NEM rule; queue functions in and out of REZs. A relatively simple change to the dispatch algorithm.	In the presence of a loop, this model reverts to the status quo, which leads to disorderly bidding.

There is potential for the model to deliver a marginal improvement in the efficiency of dispatch relative to the status quo, but it would be less accurate and dynamic than a market-based approach. New tie breaker rules would entrench race to the floor bidding in the presence of congestion, and then rely on the regulatory framework (rather than the market) to determine dispatch order.

However, the concept of the commissioning date / queue system may be valuable to provide greater investor certainty to generators with greater incumbency rather than the current position of 'winner takes all'. Access protection was a concept proposed in multiple key industry body submissions.

While the tie-breaker rules have not been shortlisted for consideration, the allocation metric based on a higher queue position has been adopted in section 3.3.

D.2 Dual price floors

The ESB notes that this model was not put forward by its original proponents, rather it was recommended for further consideration by another stakeholder. The model option has not been shortlisted for consideration by the ESB since it does not improve efficient dispatch outcomes.

The ESB notes that the AEMC has written to the ESB to note that a rule change request has been lodged by Snowy Hydro to ask the AEMC to consider amendments to the NER to address the issues for dispatchable resources lacking access to the market in times of congestion. It offers a dual price floor – one for dispatchable resources and another for semi-scheduled resources as a solution. The AEMC notes that the rule change request raises issues that intersect with work currently being undertaken by the ESB on access and the Panel on reliability standard and settings review. The AEMC will not yet initiate the rule change request until after the work of these two elements is complete given the complexity of assessing the request on its merits in light of these ongoing processes.

D.2.1 High level design

The model[39] proposes a dual floor price so that the:

- market floor price is lifted for semi-scheduled plant (variable renewable energy)
- market floor price of -$1,000/MWh remains unchanged for scheduled generation.

The model intends to solve for congestion issues reducing market access for dispatchable generators. It is designed to improve dispatch certainty for dispatchable generators by ensuring they are prioritised for dispatch during periods of volatility.

The ESB notes that this model was designed in a different context to the other models. It is designed to manage access risk for a sub-set of market participants – dispatchable generators – given their critical role in offering the hedging contracts that enable market participants to manage the risk of volatile spot market outcomes.

Table 26 Core features of dual price floors model

Feature	Model proposal
Efficient dispatch outcomes How does the model dispatch the cheapest available combination of resources to securely meet demand?	This is not a feature of the model.
Signals for congestion relief How does the model create incentives for demand side and two-way technologies to help to alleviate congestion?	This is not a feature of the model.
Managing inter-regional flows How does the model ensure efficient use of the transmission system when inter regional flows are affected by congestion?	This is not a feature of the model.

39 Model design is based on the Rule Change Proposal submitted by Snowy Hydro Limited to the AEMC, Snowy Hydro Rule change request- Dual-Floor Price - Transmission Access Risk, December 2021.

Feature	Model proposal
Allocating the value arising from regional pricing How does the model allocate the value arising from the use of regional pricing?	As per the status quo, this model allocates the value of regional pricing to parties that are dispatched – which in this case is likely to be scheduled generators.
Integrating with jurisdictional schemes How does the model support jurisdictional REZ schemes?	This model can be applied in conjunction with State government REZ schemes because REZ schemes are focussed on investment timeframes rather than how those assets operate.

D.2.2 Assessment

The ESB has assessed this model as a means of achieving the transmission access reform objectives set out above. This model is designed to take effect in operational timeframes, not investment timeframes. However, given the advantage it confers on scheduled generators, it is likely to promote investment in dispatchable generation at the expense of lower-cost VRE generation.

The model does not create incentives for generators to bid their true costs. It relies on race to the floor bidding to give dispatchable generators a mechanism to be dispatched ahead of other forms of generation. In the presence of congestion, this model is likely to result in scheduled generation being dispatched ahead of semi-scheduled generation. Given that scheduled generation typically has higher marginal costs that semi-scheduled generation, this feature inadvertently runs counter to the objective of efficient dispatch outcomes.

Table 27 Assessment of dual price floors model

Assessment criteria	Pros	Cons
Efficient market outcomes - investment	Model encourages investment in new dispatchable capacity.	Scheduled generators would be indifferent to the impact of their locational decisions on semi-scheduled generators. Semi-scheduled generators would face distorted investment signals to avoid locations near scheduled generators.
Efficient market outcomes – dispatch	N/a	This model results in less efficient dispatch outcomes that the status quo by systematically prioritising more expensive forms of generation.
Appropriate allocation of risk	N/a	This model shifts congestion risk away from scheduled generators to semi-scheduled generators.
Manage access risk	This model changes the regulatory framework to confer more access certainty on scheduled generators.	The additional certainty for scheduled generators comes at the expense of semi-scheduled generators.
Effective wholesale competition	The proponent contends that this model will promote competition in the contract market (which sits outside the National Electricity Rules).	This model distorts competition in the spot market by conferring an advantage on a particular sub-set of generators.
Implementation considerations	This model has the potential to be low cost to implement.	it would be necessary to develop mechanisms to enforce the dual price floors.

The ESB recognises that this rule change proposal was not developed in the context of the ESB's transmission access work strand a However, this model was suggested to the ESB for consideration by another party in their response to the project initiation document.[40] As noted above, the AEMC wrote to the ESB about its intentions for this rule change.

The ESB considers that the dual price floors mechanism conflicts with the access reform objectives. In particular, the model undermines dispatch efficiency in operational timeframes. The ESB's capacity mechanism workstream is exploring other options for ensuring that sufficient dispatchable capacity is available when needed.

This rule change will be considered by the AEMC through its future process.

40 See CS Energy submission, page 2. Available at: CS Energy Response to Project Initiation Paper CMM

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