ENERGY SECURITY BOARD

Transmission access reform

Directions paper

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List of abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CEC	Clean Energy Council
CEIG	Clean Energy Investor Group
CMM	Congestion management model
CRM	Congestion relief market
DMO	Default Market Offer
EOI	Expressions of interest
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
GCG	Generation Capacity Guide
GW	Gigawatt
IRSR	Inter-regional settlement residue
ISP	Integrated System Plan
LGC	Large scale generation certificate
LHS	Left hand side of a constraint equation
LMP	Locational marginal price
LRIC	Long run incremental cost
MLF	Marginal loss factor
MW	Megawatt
MWh	Megawatt hour
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net present value
PEC	Project EnergyConnect
POE	Probability of exceedance
PPA	Power purchase agreement
REZ	Renewable Energy Zone
RHS	Right hand side of a constraint equation
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
RRP	Regional Reference Price
SRMC	Short run marginal cost
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
TQM	Transmission queue model
TWh	Terawatt hours
VDO	Victorian Default Offer
VRE	Variable renewable energy
WTP	Willingness to pay

Executive Summary

Why is reform needed?

As the National Electricity Market (NEM) transitions towards higher levels of variable renewable energy (VRE), substantial new investment in transmission is needed. Governments are getting involved to deliver this new investment via Rewiring the Nation and various State government initiatives.

Network investment needs to be co-ordinated with supply-side developments so that we achieve maximum decarbonisation benefits at minimum cost to consumers. The scale and cost to consumers of the optimal development path is already significant. To protect consumer and taxpayers' interests, it is vital to ensure that all our existing and new infrastructure is used as efficiently as possible, benefitting consumers.

In light of these challenges, State governments have sought to promote more co-ordinated system development by establishing renewable energy zones (REZ) within their regions. The work of the Energy Security Board (ESB) aims to support and dovetail with these initiatives. The current NEM design puts REZ schemes at risk because there is no way to protect REZ generators from being curtailed due to developments outside the REZ. The access regime gives rise to a version of the "tragedy of the commons", comparable to the use of water resources or global fishing stocks.

Transmission congestion will increase, even as we build new transmission. AEMO's Integrated System Plan (ISP) forecasts the ideal level of curtailment if we deliver a least cost transition that follows the optimal development path. The modelling suggests the least cost way to deliver the energy transition is to build more VRE generation than the network can fully accommodate, even if we cannot use all output produced during the sunniest or windiest periods.

Even with an efficiently designed system, the volume of unused VRE in the NEM increases 16-fold between 2025 and 2050, from 5 to 80 terawatt hours (during this time forecast utility-scale VRE capacity also increases from 24 gigawatts to 140 gigawatts).[1] In the absence of reform, actual levels of curtailment are likely to exceed the levels forecast in the ISP. The ISP models the suite of transmission and supply-side projects that together deliver the optimal development path, but there is no requirement for generators to locate in accordance with the ISP.

The current market design is misaligned with the ISP because market participants receive price signals that make it profitable for them to locate in places, and bid in ways, that do not align with the lowest overall cost to consumers. 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 existing renewable generators. This adds pressure to customer prices because renewable investments are riskier than they need to be. At the same time, storage and hydrogen are not rewarded for locating in areas of the grid where they can soak up excess renewable generation.

Transmission access reform creates incentives for storage and flexible loads (such as hydrogen) to locate in REZs and operate in ways that alleviates congestion. At present, storage and flexible loads face the same price wherever they are in a State, which means they have no reason to locate in places where they could provide most value to the grid, nor to operate in ways that soak up surplus energy. Fewer subsidies would be required to underpin investments if we introduce reforms that reward storage and flexible loads for the valuable services that they provide.

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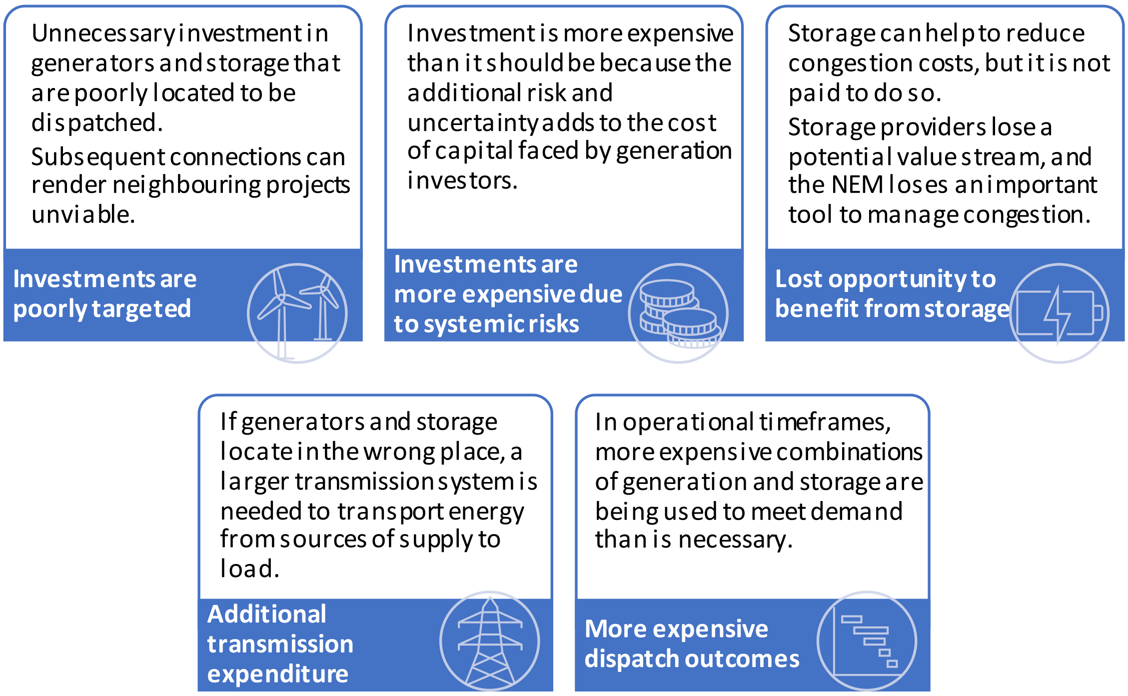
1 Unused VRE refers to the aggregate volumes of generation curtailment and spill.

If we don't change the transmission 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 (Figure 1).

Figure 1 Consequences of failing to act on access reform



The transmission planning framework recognises that it is often cheaper to build transmission to relieve congestion than to write off poorly located generation projects with sunk capital costs (given the need to build new generation to replace the poorly located generation). As customers pay for transmission, project developers (generators or storage providers) are not exposed to these additional network costs. The existing arrangements transfer the risk of excess transmission costs arising from poor locational decisions by developers to consumers. A key goal of transmission reform is to reduce the risk of inefficient network build, and to allocate the risk of locational decisions to generators. This will mean that network capacity is only built where it is needed and that government programs including REZ initiatives and Rewiring the Nation are able to achieve more.

The current regime means we are also likely to end up dispatching more expensive and carbon intensive combinations of generators than we need. Locational signals provided by our regional pricing model are not granular enough to manage congestion within regions well. When congestion occurs, the National Electricity Rules require the market operator to use blunt heuristics to decide who to dispatch. The results can be inefficient, such as instances where the market unnecessarily spills wind or solar in order to dispatch more coal, gas, hydro or batteries.

The current mechanism for deciding who gets dispatched in the presence of congestion is a function of complex interrelated technical factors, which means that outcomes are opaque, volatile and hard to predict for all but the most sophisticated industry participants. Dispatch outcomes can have 'winner takes all' characteristics and projects are exposed to the risk of cannibalisation (where a new entrant does not add usable new VRE to the power system and instead displace pre-existing generators). This unpredictability adds to the cost of capital faced by investors, with the result that investing in the NEM is more expensive than in other comparable markets.

These challenges can be distilled into the transmission access objectives shown in Figure 2.

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.	

Process to date

National Cabinet has instructed the ESB to progress detailed design work on transmission access reform for the NEM. 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.[2]

The ESB has subsequently engaged extensively with stakeholders on the detailed design and is considering alternative models put forward by stakeholders. In particular:

- the Clean Energy Council has outlined a concept for a congestion relief market that has the potential to meet the ESB's objectives for access reform in operational timeframes
- the Clean Energy Investor Group has outlined a concept for a transmission queue that has the potential to meet the ESB's objectives for access reform in investment timeframes.

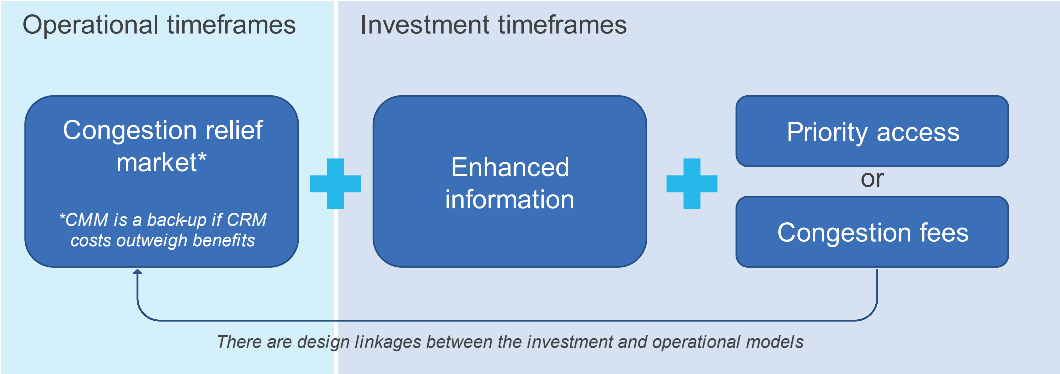
In May 2022, the ESB consulted on four shortlisted models to manage congestion in the NEM, including the two models put forward by industry. Since then, we have worked with the Congestion Management Technical Working Group and expert consultants to gain a better understanding of how the shortlisted models would work in practice, and their respective strengths and weaknesses. The ESB has taken on board stakeholder feedback to develop a preliminary hybrid model that mixes and matches the best elements of previous shortlisted models.

Overview of model

The hybrid model is designed to incorporate stakeholders' feedback and ideas in a way that best promotes the access reform objectives, in the overall interests of consumers. The hybrid model combines measures that apply in both operational and investment timeframes. To get the benefits of the reforms, it is necessary to do both. If the reforms only encompass investment signals, the signals could be undermined in real time. If the reforms only take effect in operational timeframes, then the market design would continue to send poorly targeted locational signals to investors.

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

Figure 3 Core elements of hybrid model



Note: CMM refers to the congestion management model.

There is merit in further work to develop a detailed design for the congestion relief market (CRM) and enhanced information. These model elements enjoyed relatively strong support in submissions to the consultation paper. The CRM shares a lot of the same mathematical foundations and benefits as the ESB's original proposal (the congestion management model or CMM) but it has the potential to deliver additional benefits. In particular, it gives market participants a tool to manage their exposure to more localised price signals because they can opt out of participating in the CRM.

However, more work is required to develop the detailed design and ensure that it does not give rise to unintended consequences. If it becomes apparent that the CRM does not provide additional benefits that are commensurate with the additional complexity and cost, the ESB proposes to revert to the CMM. The CMM also delivers efficient dispatch outcomes and incentives for market participants to operate in ways that alleviate congestion, but it offers less flexibility for market participants to manage their contractual positions.

There are two key variants within the hybrid model, which reflect two different ways of signalling efficient investment locations to prospective investors:

- Priority access – this option establishes a queue in the event of tied price bids to prioritise access to the RRP.
- Congestion fees – the option leverages the transmission planning process to administer fees that reflect the level of available hosting capacity for new generation.

It will be important to balance the need to provide improved 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. Access reform is inherently complex and all options require difficult trade-offs. However, failing to act means accepting that the energy transition will be less orderly and more expensive for customers.

The choice between priority access and congestion fees represents a fork in the road for the development of the model. In addition, the ESB seeks stakeholder views on 23 detailed design choices to be included within our recommendations to Ministers.

We anticipate that any of the models – but particularly those that involve changes to the dispatch engine and accompanying market systems – will involve substantial, multi-year lead times. The time needed to implement the reforms will depend on which model is adopted. The ESB will consider whether there are potential benefits associated with a staged approach to implementation. Such benefits could include providing lead time for new arrangements to be reflected in new contractual arrangements, and time for older contracts to roll off. Any benefits of a staged approach are likely to depend on which variant of the hybrid model is adopted.

Next steps

The preliminary hybrid model is the product of the ESB's efforts to work closely with stakeholders to develop a package of reforms to manage congestion in the NEM. The purpose of this directions paper is to seek stakeholders' feedback on the hybrid model and the detailed design choices within it.

At the recent Energy Minister Meeting, Ministers tasked Senior Officials to jointly undertake stakeholder consultations with the ESB on the full range of options for transmission access reform (including additional options that are not set out in this paper), with recommendations to be considered at the first Energy Ministers' Meeting in 2023.[3] The ESB is working with Senior Officials to determine the nature and scope of the additional consultation and will update stakeholders shortly.

Both responses to this Directions Paper, and the outcomes of the additional stakeholder consultation to be conducted in collaboration with Senior Officials, will inform the ESB as it develops its draft recommendations. Submissions on this paper are due by 21 December 2022. The ESB will hold a public webinar on 5 December 2022 to assist stakeholders with their submissions.

3 See Energy Ministers' Meeting Communique, 28 October 2022. Available at: https://www.energy.gov.au/government-priorities/energy-ministers/meetings-and-communiques

1 Introduction

1.1 Purpose of document

The ESB is working to develop a package of reforms to manage congestion in the NEM. The ESB has developed a preliminary hybrid model that mixes and matches the best elements of previous shortlisted models.[4] The hybrid model is designed to incorporate stakeholders' ideas in a way that best promotes the access reform objectives, in the overall interests of consumers.

This paper represents the ESB's preliminary thinking on the model design that we could ultimately recommend to Ministers. There are two key variants, which reflect two different ways of signalling efficient investment locations to prospective investors:

- Priority access – this option establishes a queue in the event of tied price bids to prioritise access to the RRP.
- Congestion fees – the option leverages the transmission planning process to administer fees that reflect the level of available hosting capacity for new generation.

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

Access reform is inherently complex and all options require difficult trade-offs. However, failing to act means accepting that the energy transition will be less orderly and more expensive for customers.

The purpose of this directions paper is to seek stakeholders' feedback on the preliminary hybrid model. This will guide the ESB as it further develops a draft preferred model, including the various choices in the detailed design of a model.

1.2 Background

1.2.1 Ministers' request

National Cabinet instructed the ESB to progress detailed design work on transmission access reform. The ESB is working to recommend a rule change for a preferred model to Energy Ministers by June 2023. To deliver on this task, the ESB continues its work 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.[5]

4 Refer to shortlisted models from the previous Transmission access reform consultation paper, May 2022.

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

1.2.2 Consultation process

In October 2021, National Cabinet 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. 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.[6]

Key points of consultation have included:

- Project initiation paper, released November 2021: in response, stakeholders submitted alternative models to the ESB's preferred model at the time (CMM adapted for REZs). The ESB engaged with stakeholders to understand their proposals and identify the best features of the proposed model designs.
- Transmission access reform consultation paper, released May 2022: The ESB shortlisted four out of the ten models in a consultation paper. In addition, the paper outlines the ESB's access objectives and assessment criteria which were developed in collaboration with the ESB's Congestion Management Technical Working Group (see chapters 2 and 3 below).
- This directions paper, released November 2022: the ESB enhanced its stakeholder engagement process before publishing this directions paper. This included weekly meetings of the Congestion Management Technical Working Group, as well as bilateral and peak body briefings. The papers and minutes from the technical working group meetings are published on the ESB's website.[7] We have also invited all stakeholders (not just those in the working group) to provide informal verbal or written feedback on key working group papers.

1.2.3 Process going forward

The preliminary hybrid model is the product of the ESB's efforts to work closely with stakeholders to develop a package of reforms to manage congestion in the NEM. The purpose of this directions paper is to seek stakeholders' feedback on the hybrid model and the detailed design choices within it.

At the recent Energy Minister Meeting, Ministers tasked Senior Officials to jointly undertake stakeholder consultations with the ESB on the full range of options for transmission access reform (including additional options that are not set out in this paper), with recommendations to be considered at the first Energy Ministers' Meeting in 2023.[7] The ESB is working with Senior Officials to determine the nature and scope of the additional consultation and will update stakeholders shortly.

Both responses to this Directions Paper, and the outcomes of the additional stakeholder consultation to be conducted in collaboration with Senior Officials, will inform the ESB as it develops its draft recommendations.

Update regarding modelling of options
The ESB is working with NERA Economic Consulting to model the changes in dispatch and financial outcomes arising from different design choices in the operational timeframes. Modelling results will be published as an addendum to this paper. The ESB will make this information available as soon as possible so that it can inform stakeholders' responses to the Directions Paper.

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

7 See Energy Ministers' Meeting Communique, 28 October 2022. Available at: https://www.energy.gov.au/government-priorities/energy-ministers/meetings-and-communiques

2 Drivers for reform

2.1 Case for change

Access reform is needed for the following reasons:

- to deliver a least cost energy transition by investing in the right places
- to ensure that investors aren't exposed to unnecessary risk
- to make sure that REZ schemes deliver expected benefits
- to facilitate investment in storage and flexible loads
- to optimise the size of our transmission network
- to ensure we use the least cost combination of available resources.

This chapter describes the case for change and outlines the ESB's objectives for transmission access reform.

2.1.1 To deliver a least cost energy transition, we need to invest in the right places

In the absence of arrangements that provide clear signals to generators and storage about where it would be efficient to build and how to utilise the network, outcomes will continue to be uncoordinated and lead to higher overall costs.

New generation and storage will continue to locate and operate in ways that are inconsistent with minimising total system costs. One likely consequence is elevated congestion, which means electricity cannot be dispatched to meet demand at the lowest possible cost. In turn, this will drive the requirement for more transmission investment to alleviate the congestion, which would not have been needed if the investment and operation of generation and storage had been efficient. The cost of this additional transmission investment is borne by consumers.

These market-driven distortions are not contemplated in the ISP, which is an engineering assessment designed to minimise total system costs. The ISP model identifies the optimal development path for the transmission system based on the optimal siting and design of new generation and storage developments from a whole of system perspective. However, under the NEM's regional pricing model, there is no commercial driver for investors to choose the efficient locations identified in the ISP. If the market design encourages patterns of generation investment that do not align with the ISP, the ISP modelling will perpetually adjust in response to developments on the ground – and the adjustments are likely to be more costly than if investment had occurred in line with the original plan and network investment.

Due to the way electricity flows across the grid, constraints outside REZs will be felt inside each REZ and vice versa.[8] This can only be addressed through transmission access solutions that apply across the whole system, of which REZs are a part.

Under the current access regime, even an investment that causes heavy congestion may still be profitable for an investor, because the costs of congestion may be borne in part by pre-existing generators rather than fully by the new party that caused the congestion. This is because the NEM's current access regime permits any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to the broader power system – and then the new generator may gain free access to the network at the expense of existing generators.

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8 This issue is discussed in more detail in the ESB's Renewable Energy Zones Consultation Paper, January 2021, p. 20. See: https://energyministers.gov.au/publications/stage-2-rez-consultation-energy-security-board

The ESB's hybrid model seeks to change this aspect of the access regime so that a generator whose investment decision causes inefficient congestion faces the associated costs, and a generator who locates where capacity is available, such as a REZ, is protected from subsequent connection risk.

The right NEM-wide arrangements will also ease pressure on other aspects of the market framework that currently bear the brunt of uncoordinated developments. As generators connect to parts of the system that are already full due to the NEM's malfunctioning access regime, problems manifest in the form of low and volatile marginal loss factors and an unpredictable, lengthy connections process.[9]

Congestion will increase, even after the actionable ISP projects are built

Congestion is a normal, everyday feature of efficiently sized transmission infrastructure to accommodate variable renewable generation – not an anomaly. Globally, power systems are experiencing an increase in congestion costs in line with an increase in variable renewable generation. Congestion is likely to increase because the cost of building the incremental transmission infrastructure needed to allow the dispatch of variable renewable generation at the sunniest or windiest of times exceeds the benefits of reducing the cost of dispatch or reducing emissions at those times from the dispatch of VRE. It is more cost effective, and reduces emissions by a greater extent, to build more variable renewable generation than can always be accommodated by the transmission infrastructure, even if that variable generation cannot always be used.

AEMO's 2022 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 expansions foreshadowed by the ISP. The additional transmission hosting capacity projected in the ISP is less than half the additional utility-scale VRE capacity.

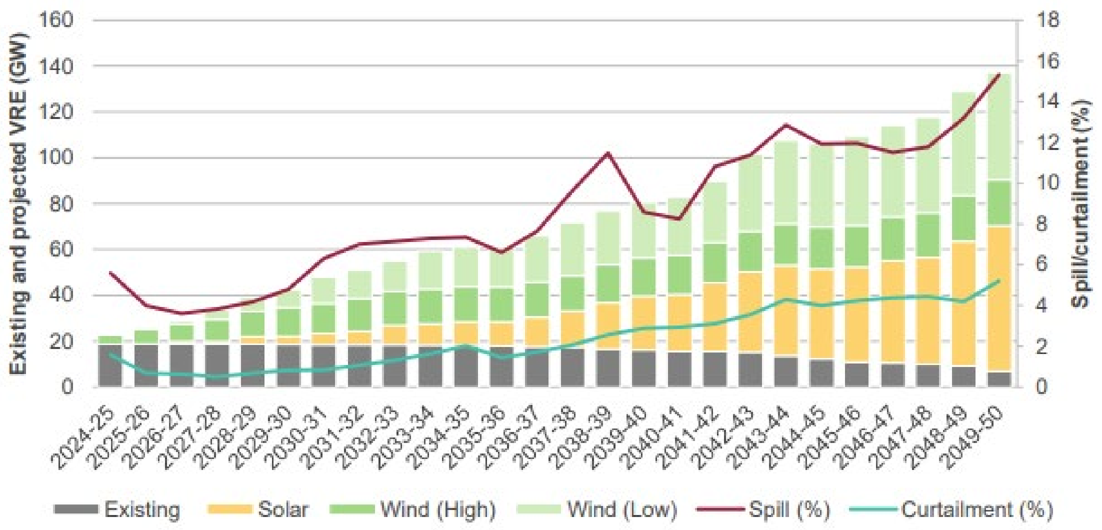
To accommodate approximately 135 GW of utility-scale VRE by 2050, the forecast economic spill is 15% and transmission curtailment is approximately 5%.[10] In contrast, in Q2 2022, VRE curtailment was on average 1.1% of available VRE generation in the NEM.[11] As the ISP has perfect foresight within the confines of the modelling exercise, these levels can be considered the best-case scenario. In the absence of reform, actual levels of curtailment are likely to exceed the levels forecast in the ISP. The ISP models the suite of transmission and supply-side projects that together deliver the optimal development path, but there is no requirement for generators to locate in accordance with the ISP.

9 While thermal constraints are not of themselves a barrier to connection, increasing generation in already congested parts of the grid can exacerbate system security risks, which makes the process of negotiating generator performance standards more complex.

10 Economic spill happens when generation reduces output due to market price. Curtailment happens when generation is constrained down or off due to operational limits.

11 AEMO, Quarterly Energy Dynamics Q2 2002, July 2022, p 39. Available at: https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf?la=en

Figure 4 Projected utility-scale VRE in REZ for the NEM, economic spill and transmission curtailment



Source: *AEMO, Appendix 3 Renewable Energy Zones 2022 ISP for the National Electricity Market, June 2022, p. 14.*

The level of congestion shown in Figure 5 is likely to understate true levels for a number of reasons. First, the modelling is focussed on congestion occurring during system normal conditions as the complexity of the modelling task means that it is not feasible to include network outages. In practice, significant proportion of congestion arises outside system normal. In 2021, 41% of the costs of constraints arose under system normal conditions, 34% arose during network outages, and the remainder occurred for other reasons, including FCAS constraints, commissioning and clamping.[12]

The second reason why actual levels of congestion are likely to be greater than forecast is that 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 settled at 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. When FTI ran a sensitivity to explore the impact of additional solar capacity over and above the amount modelled in the ISP, the potential incremental solar output was reduced by over 20 per cent due to constraints.[13]

Congestion costs will increase, even with a high VRE system

Even in a power system dominated by VRE generation, there will still be costs to congestion:

- Synchronous generation which provides system strength, inertia and frequency and other services is likely to operate during periods of high inverter-based generation such as VRE.
- This would include a modest amount of thermal generation to provide a range of services, which could be fuelled by gas or hydrogen. This generation will not have zero marginal costs.
- Storage and hydro generation have opportunity costs and hence will not necessarily bid at zero price.
- Flexible loads will suffer opportunity costs when they are curtailed.

The NEM has a high market price cap, or maximum price that generators and storage may bid at the regional reference node. The level of the cap provides some incentive for investment in flexible

12 AEMO, NEM Constraint Report 2021 Summary data

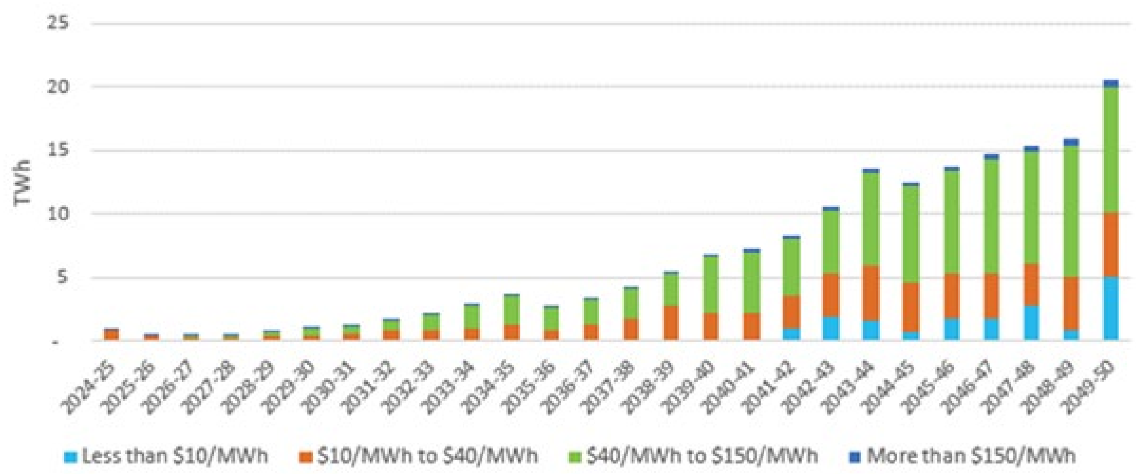
13 FTI Consulting, Forecast Congestion in the NEM, 5 August 2022. Available at: https://www.datocms-assets.com/32572/1629773972-fti-esb-forecast-congestion-in-the-nem-final-5-august-2021.pdf

dispatchable plant, especially plant that is required to maintain reliability but rarely used. It is expected that there will be occasional high prices up to the market price cap.

Stakeholders are correct to point out that there will be higher levels of curtailment at a low price point in future. However, the volume of curtailment increases significantly over this time so there is actually a total higher value of curtailment. In the longer term, the distribution of RRPs may be dominated by zero prices (or negative prices reflecting the opportunity cost of not generating LGCs) but there will also be periods of high prices.

Figure 6 shows the volumes of curtailed energy within REZs by price distribution. This analysis focuses on transmission curtailment, not economic spill, and hence the data series is already adjusted to exclude volumes of economic spill with value less than $10/MWh.

Figure 5 REZ volumes of VRE curtailment by price distribution (excluding economic spill)



Source: ESB analysis of AEMO 2022 ISP data [14]

2.1.2 To ensure REZ schemes deliver expected benefits

REZs are a regulatory tool to deliver more efficient and effective connection of renewables to the grid. Several jurisdictions are developing REZ schemes in their regions. The ISP takes into account the location and scale of these REZs and the optimal development path includes transmission development to support them.

The ESB expects the transmission infrastructure relating to REZs to be designed to host a defined level of generation and storage capacity that will be met through a jurisdictional process, such as the process being undertaken in accordance with the NSW Electricity Infrastructure Roadmap.

While access with each REZ can be managed through a jurisdictional REZ arrangement, the overall value of a REZ, both to prospective investors and to the NEM, is subject to the broader access to the national grid. Under the current open access regime, participants could choose to connect to the grid at any point outside the REZ. Subsequent connections could reduce the access available to parties in

14 Analysis based on Figure 28 Forecast NEM price distribution of generation curtailment or spill, Step Change (Appendix 4, ISP 2022) https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a4-system-operability.pdf?la=en Figure 7 Projected utility-scale VRE in REZ for the NEM, economic spill and transmission curtailment (Appendix 3 ISP 2022) https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a3-renewable-energy-zones.pdf?la=en, Annual as generated generation by REZ, Step Change CDP12 (Generation Outlook, 2022 Final ISP results workbook) https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/generation-outlook.zip?la=en

the REZ and degrade the value of connecting within the REZ. It is also possible that a well-placed connection outside of the REZ could gain preferential access in dispatch.

In the medium to long term, the NEM's extreme version of open access is incompatible with REZs because it is an unstable foundation for co-ordinated system development. At present, generators can connect where they want,[15] including in parts of the system where there is no spare capacity available. They don't have to contribute to the cost of the shared transmission system.[16] As a result that new projects can take advantage of network investments that were intended to provide access for REZ generators. Prospective investors may find it simpler and cheaper to connect just outside the REZ than to participate in a REZ tender process.

Connections outside of REZs could be prohibited to address this problem, although this solution runs against the grain of encouraging more VRE generation to connect to reduce costs, improve reliability and reduce emissions. Alternatively, transmission access reform can 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 investments that locate outside the REZ in the broader shared network
- allowing market participants to connect outside of REZs, without disrupting the coordinating efforts of the REZ
- 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

2.1.3 To ensure that investors aren't exposed to unnecessary risk

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 co-optimised dispatch algorithm that determines the output of each generator 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 finds the least cost way of dispatching generation out of the options available and based on generators' bids.

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 constraint coefficient, contribution factor or participation factor), which reflects the impact it has on

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15 Subject to meeting minimum performance standards.

16 Other than for system strength: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

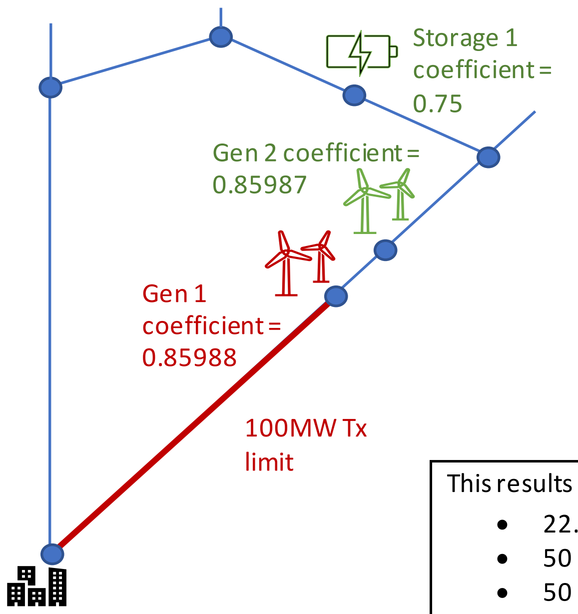
the constrained transmission line.[17] The coefficient measures the impact to the constrained line from a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector).[18] The coefficient reflects the proportion of a generator's output or interconnector's flow which "uses" the equipment to which the constraint relates – it measures each generator's contribution to each constraint. 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 cost of congestion by dispatching generators with the lowest coefficients first.

This feature of dispatching tied bids based on coefficients gives rise to "winner takes all" outcomes when a single network constraint is affecting the dispatch of generators. The winners and losers associated with coefficients in particular constraints vary over time, as generators enter and exit the market, their availabilities change and demand patterns change, and AEMO's constraint equations change to reflect these events.

Figure 7 shows how if a generator locates in a congested location – but with a lower coefficient than their neighbours for relevant constraints – then, other things being equal, they will be dispatched ahead of their neighbours when congestion occurs.

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:

$0.85988 \times G1 + 0.85987 \times G2 + 0.75 \times S1 <= 100$

Where G1, G2 and S1 are the dispatch quantities (MW) of Gen 1, Gen 2 and Storage 1 respectively where Storage 1 is acting as a generator.

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

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

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

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17 AEMO, Constraint Implementation Guidelines, June 2015

18 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'.

The constraint formulation that determines 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. 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 constraint coefficient, 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. In the example above, were a third 50MW generator to locate immediately to the north of Generator 2 it would have a lower coefficient and hence be dispatched for 50MW, constraining Generator 1 and Generator 2 down. This extreme version of open access makes investing in the NEM riskier than other comparable markets.

In other major electricity markets, generators pay to access the transmission network via an upfront fee and/or or in real-time via 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. As result, investors face less risk of curtailment as a result of subsequent connections displacing their output.

In almost any other market – for electricity or anything else – sellers either trade at their local price and the consumers pay for transport from that location, or the commodity is traded at a central hub price with the seller paying for transport themselves. The NEM is unusual – both in comparison to other electricity markets and to other commodity markets– in that the sellers enjoy free transport to the hub (paid for by the buyer), and yet the transaction for the commodity occurs at the hub price. While prices received by generators are adjusted to reflect their marginal loss factors, this is analogous to the seller having to cover the cost of goods that are lost in transit rather than the cost of transport.

2.1.4 To facilitate investment in storage and flexible loads

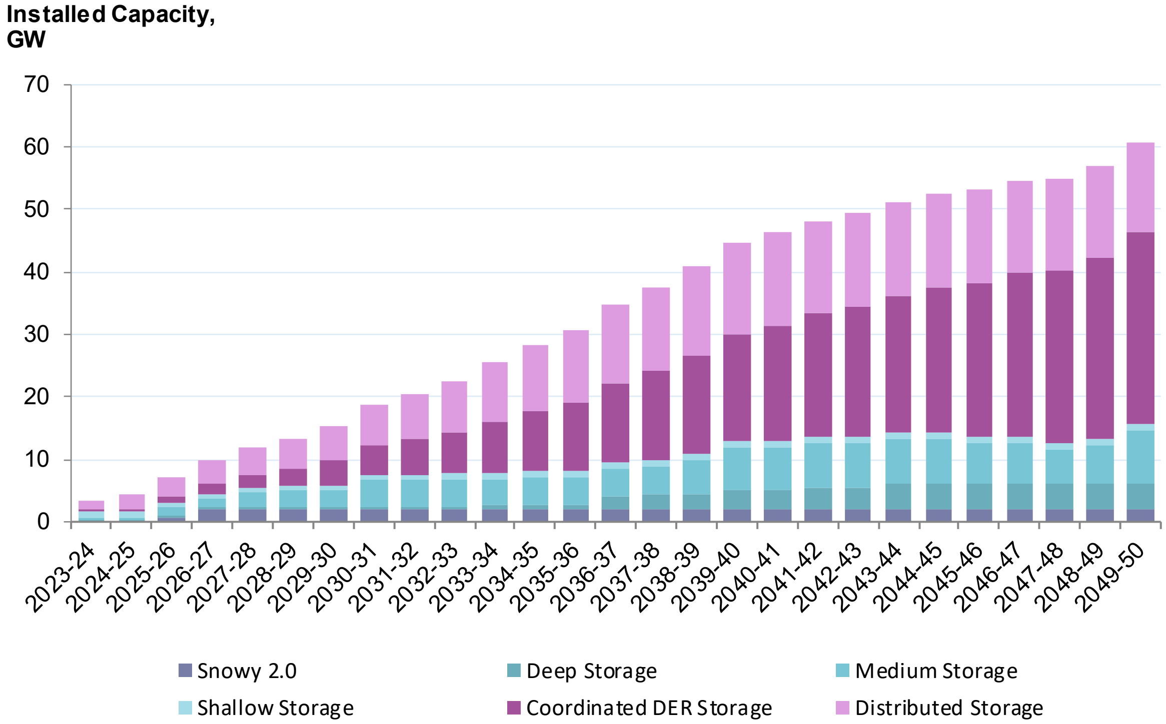
The right NEM-wide transmission access regime will help us to stay ahead of, and facilitate the efficient investment in, the expected dramatic increase in large-scale battery deployment and emerging technologies such as hydrogen. A large flexible load, grid connected hydrogen could be a source of demand response on the horizon, which can help make the system stable. These technologies need incentives so that they charge (use energy) and discharge (not use energy) at the times that are most valuable. That way they align with, and not against, a high variable renewable energy power system. Investors should have the opportunity to be rewarded for leveraging the flexibility of these technologies. This section presents case studies for storage and hydrogen.

Case study 1: Storage

As of January 2021, the storage capacity of the chemical battery fleet in service in the NEM is 768 MWh. The storage capacity of all projects that have been publicly announced according to AEMO or are in the development phase is 26,201 MWh.[19] Under AEMO's 2022 ISP, substantial new investment in utility scale storage is required. Therefore, it is important that the market design incentivises efficient operation and location of battery storage.

19 AEMO. (2022). *NEM Generation Information August 2022.*

Figure 7 NEM storage MW capacity in the least-cost development path under Step Change scenario



Source: AEMO 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 generation 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 current market design does not typically reward batteries for alleviating congestion.[20] Instead, batteries are incentivised to behave like a generator, even though they have a broader range of capabilities. This is because it receives the same price in its region, regardless of its local congestion. If there is high congestion in its area at certain times of the day, there would be system-wide benefits for the battery to charge, alleviating congestion. However, if the regional price 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, then it should export, but again the current incentives do not create this effect. This undermines the value that batteries can offer to the system, particularly where they are needed to support flexible resources. Storage providers are missing out on a significant revenue stream, and consumers are missing out on an opportunity to efficiently reduce congestion costs.

20 Unless the battery enters into a non-network support agreement with a network services provider.

Table 1 Summary of average intra-day price spreads by NEM region ($/MWh)

Region	Average Price Spread Lowest Node	Average Price Spread RRN	Average Price Spread Highest Node	Difference Between High and Low	Difference Between High and RRN
NSW	148	216	312	164	96
QLD	310	396	433	123	37
SA	198	214	241	43	27
TAS	59	64	84	25	20
VIC	124	128	208	84	80

Source: ESB using the AEMO MMS database, 2021

To reflect typical charging/discharging durations of batteries, prices relate to the highest/lowest consecutive 2-hour block.

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.

Case study 2: Hydrogen

One of the biggest decisions facing the hydrogen industry at the moment is whether to locate on or off grid. There are many benefits to the grid of hydrogen choosing to locate on-grid – loads that can follow the output profile of variable renewable energy can absorb surplus renewable energy during windy and/or sunny periods and reduce demand during periods of scarcity. However, given the current wholesale market design, it may be cheaper for hydrogen electrolysers to locate off-grid than to connect to the NEM.[21]

The shadow LMPs produced by AEMO can serve as an estimate of the cost of congestion at a particular location on the network. The average price of the shadow LMP at Gladstone was $12.22/MWh lower than the QLD RPP in 2021. This significant difference in prices and therefore the cost of energy to a new large load like hydrogen, reflects the potential value to the underlying economics of new hydrogen production capacity, where it can locate at the lower priced nodes in each region of the NEM. While this may be a crude metric, it does give an indication of the price differences available under a framework that includes prices that reflect the impact of congestion. Given that approximately 70% of the cost of green hydrogen is the cost of electricity input, access to these price

21 MHA Khan, R Daiyan, Z Han, M Hablutzel, N Haque, R Amal, I MacGill (2021) Designing Optimal Integrated Electricity Supply Configurations for Renewable Hydrogen Generation in Australia. iScience, 102539, DOI: https://doi.org/10.1016/j.isci.2021.102539

fluctuations will be critical to support the business case for grid connected green hydrogen. The importance of having access to this significant price difference is discussed below.

Energy costs will play a key role in ensuring the hydrogen industry is competitive longer term. The CSIRO's National Hydrogen Roadmap shows that for every $10/MWh improvement in the electricity price, the cost of hydrogen is lowered by approximately $0.45/kg, assuming improvements in the efficiency of electrolysers take place.

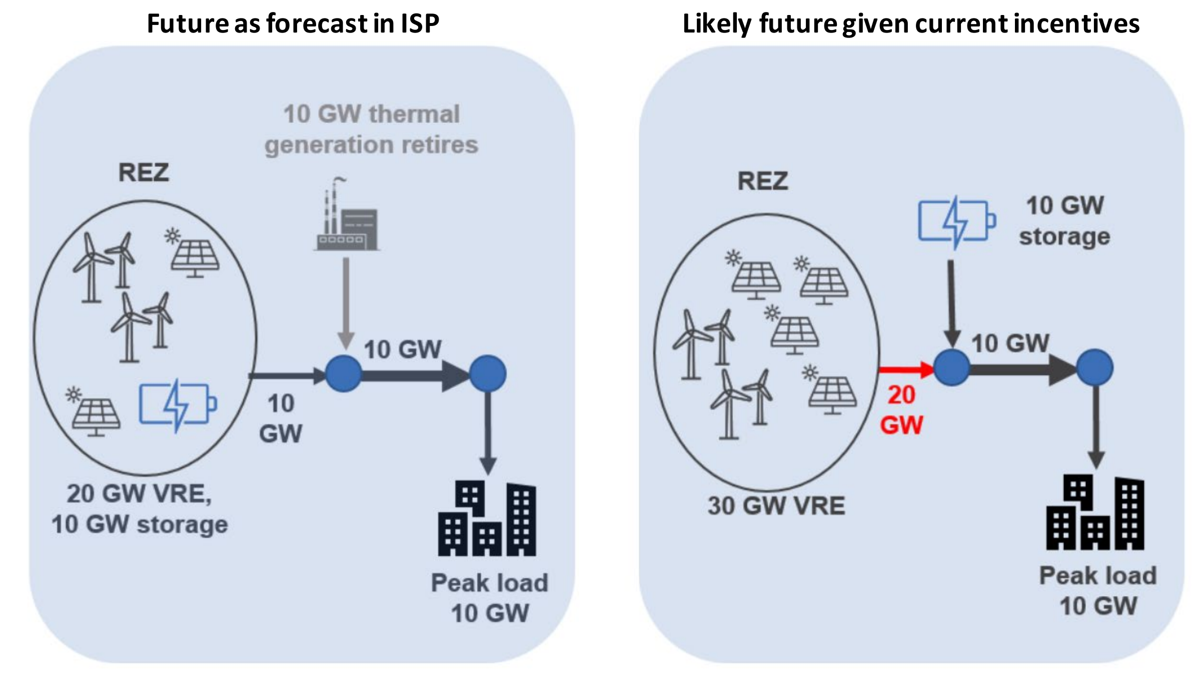
2.1.5 To optimise the size of our transmission network

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 historically we have relied on the commercial decisions of investors to decide where new generation projects should locate. As our current market design is sending the wrong signals, the least cost outcome envisaged in the ISP will not eventuate.

As discussed above, 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 8 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 GW can flow through the transmission system to supply load, and the surplus of 10 GW can be stored in the battery for later use. If the battery is not co-located with the VRE, then all 20 GW 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.

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. 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 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.

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

2.1.6 To ensure that we get the full benefits of new interconnector investments

The current access regime creates specific problems around the treatment of interconnectors and inter-regional flows. When congestion arises between a generator and its RRN, if the generator can access an interconnector, they may instead be dispatched to meet demand in a neighbouring region. This generator will still be paid the price that applies in its home region. If the price is high in the home region due to the congestion, then counter-price flows may occur.

When the accrued value of counter-price flows across an interconnector exceeds $100,000, AEMO “clamps” the interconnector (i.e. intervenes in dispatch so that the counter-price flow ceases). This requirement is designed to protect customers from large negative inter-regional settlement residue balances, which would manifest as an increase in transmission use of system charges. While there is a clear justification for clamping, it currently can result in a sub-optimal use of interconnector assets due to flaws in the current market design.

Incidences of clamping are likely to increase in materiality as REZs are developed near the regional boundaries and investment in new interconnectors results in more loop flows between NEM regions. To date, the NEM is represented by a hub-and-spoke model, where the limited interconnection topology means that there is no range in paths over which power can flow between regions. For instance, power flowing from South Australia to NSW must go via Victoria. This will change following the completion of Project Energy Connect, which will create the first loop flow among NEM regions. FTI Consulting’s analysis shows substantial growth in the number of hours of counter-price flows in 2030, especially in the NSW-Vic-SA triangle.

To the extent that these counter-price flows give rise to clamping, there is a risk that interconnector investments will not deliver the anticipated market benefits. As the need for clamping is driven by price outcomes rather than underlying costs, they are not taken into account in the ISP and RIT-T assessments. To be clear, counter-price flows are not problematic in themselves. The problem is the flaws in the market design that give rise to a need for clamping. The ESB's proposed access reforms would reduce or even remove the need for physical clamping of the interconnectors due to changes in how generators are compensated.

2.1.7 To ensure we use the least cost combination of available resources

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 regional pricing model rewards market participants for acting in a manner that is inconsistent with economic efficiency.

One such inefficiency that arises is an instance of 'race to the floor bidding'. In the presence of congestion and a high RRP, constrained generators know that the offers they make will be unlikely to affect their RRP. The profit maximising behaviour of a generator is to bid at the market floor price of -$1,000/MWh. This maximises their individual dispatch quantity, and hence the wholesale market revenue they receive (the dispatch quantity multiplied by the RRP). All generators affected by the constraints are incentivised to maximise their share of the limited transmission capacity by engaging in this 'race to the floor' bidding behaviour: not racing to the floor when one's competitors are doing so reduces the generator's share of dispatch, and hence revenue.

The NEM dispatch engine selects market participants to be dispatched by minimising total as-bid costs while ensuring that the pattern of dispatch is consistent with the physical capacity of the system. It uses as an input the bids made by market participants; it does not distinguish between the underlying actual costs of generators or the value of their contract positions. As a result, in the presence of congestion and disorderly bidding, dispatch is shared based on administered rules between generation with high and lower underlying costs, all of whom are bidding at the same price. This results in productive inefficiencies. It would be more efficient for the lower cost generation to be dispatched ahead of the higher cost generator. This ultimately results in higher prices for consumers.

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. Analysis of dispatch inefficiencies and congestion in the grid show that over time the impact and associated costs of these issues are likely to significantly increase. NERA modelling undertaken for the AEMC[22] estimates that costs arising from race to the floor bidding could reach up to NPV $1 bn over the period from 2026 to 2040 ($2020). Analysis of international case studies suggests benefits to consumers from efficient dispatch signals could be up to $137 million per year. [23]

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[23] NERA Economic Consulting, Cost Benefit Analysis of Access Reform: Prepared for the Australian Energy Market Commission, 9 March 2020.

2.2 Transmission access reform objectives

To ensure the recommended access reform model addresses the challenges with the transitioning energy system, the ESB has developed objectives and assessment criteria as critical parameters for the congestion management work. The consultation paper (May 2022) set out how the ESB finalised the objectives and assessment criteria in close consultation with stakeholders.

Our detailed design process seeks to identify the model(s) that best promotes all four of the transmission access reform objectives.

Figure 9 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:

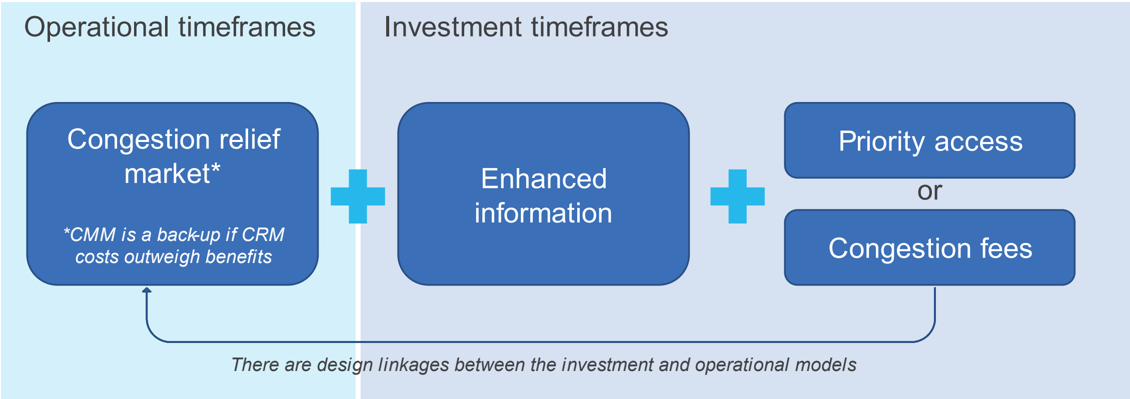
Establish a framework that incentivises technologies that can help to alleviate congestion (e.g. storage and demand-side resources) to locate where they are needed most and operate in ways that benefit the broader system.

Source: ESB

3 Outline of the hybrid model

The ESB has developed a preliminary hybrid model that mixes and matches the best elements of previous shortlisted models. The hybrid model is designed to incorporate stakeholders' ideas in a way that best promotes the access reform objectives, in the overall interests of consumers. This paper represents the ESB's thinking to date on the model design that we could ultimately recommend to Ministers. Figure 11 depicts the core elements of the hybrid model.

Figure 10 Core elements of the hybrid model



There are two key variants, which reflect two different ways of signalling efficient investment locations to prospective investors:

- Priority access – this variant integrates enhanced information, the transmission queue model (TQM) and the CRM.
- Congestion fees – this variant adopts enhanced information, congestion fees and the CRM.

This chapter discusses the core elements of the hybrid model. It then considers how the model integrates with State government REZ schemes and implementation issues before setting out the ESB's preliminary assessment against the assessment criteria.

3.1 Core elements

3.1.1 Congestion relief market

The CRM is a new market that incentivises efficient dispatch outcomes in addition to those produced by the existing energy market. The proposed design envisages two optimisation runs, one for energy dispatch (paid at RRP) and one for incremental dispatch in the CRM (paid at LMP). It encourages providers of congestion relief (such as storage and flexible loads) to locate in congested parts of the network and operate in ways that minimises total system costs.

The ESB is developing a detailed design for the CRM, which is the proposed model to address congestion issues in operational timeframes. There are two core benefits:

- The CRM design creates a new market to achieve a more cost-efficient dispatch. The efficiency gain is shared between CRM participants. It enables the efficient operation of the network's significant transmission investments.
- The CRM unlocks a new market for congestion relief and recognises the value that storage and scheduled load can provide to the energy system.

The CRM shares a lot of the same mathematical foundations and benefits as the ESB's original proposal (the congestion management model or CMM) but generator representatives prefer it to the CMM because:

- It enables market participants to manage their exposure to LMPs, by automatically allocating access to the RRP in the same way as under current arrangements
- It gives market participants visibility of access and dispatch outcomes in pre-dispatch and real time, rather than in subsequent settlements
- It provides a more straightforward basis for hedging contracts with congestion relief providers.

A key feature of the CRM is that participants can opt out and maintain the dispatch outcomes determined by the energy market. This opt-out recognises that participants have other costs to consider, including existing contract positions and transaction costs. Customer representatives, in particular Energy Consumers Australia, have expressed concern about the opt out feature on the grounds that:

- the benefits of the reforms will be reduced if market participants choose to opt out, and
- the opt out feature introduces complexity and cost.

Given the additional profits available from the CRM, the ESB expects contract terms to adjust so that contracting parties share the benefits. The opt out provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements. Considerations of contract arrangements are provided in Appendix D.

Given that the two models are so similar in terms of their economic principles, and generators are strongly of the view that the CRM will impose fewer costs on them, the ESB considers that there is merit in further exploring the detailed design of the CRM.

However, electricity market design is complex, and the CRM is a new concept that has not been attempted in other jurisdictions. There is a risk that we will uncover policy and/or implementation issues that are difficult to resolve. For instance, we expect the model to have complex impacts on bidding in the energy market, which could become detached from dispatch outcomes. More work is required to develop the detailed design and ensure that the reform does not give rise to unintended consequences.

If the CRM does not provide additional benefits that are commensurate with the additional complexity and cost, the ESB proposes to revert to the other shortlisted operational model, the CMM. We will continue this work while the Directions Paper is published for consultation. Details of the CMM are provided in Appendix E. We note that the CMM has had the benefit of detailed consideration during previous reviews, which means that it is well progressed relative to the CRM.

3.1.2 Enhanced information

> The ESB is exploring measures to provide prospective investors with information about which parts of the network are available for further development, which parts are reaching capacity, and which parts are already full.

Enhanced congestion information enjoys broad stakeholder support. It is a 'low regrets' policy that supplements the hybrid model by helping to promote more informed investment decisions. The ESB is working with stakeholders to identify what information could be usefully provided, having regard to the costs and the different use cases for the information.

The TNSPs and AEMO are well placed to advise on technical limits of the transmission network, but less well placed to take a position on the commercial prospects of a new project.

Enhanced information is not proposed as a standalone solution as it does not remove incentives for inefficient investment. We note that this solution was already adopted during an earlier NEM access review 14 years ago.[24] It led to the establishment of AEMO's Congestion Information Resource, which remains a useful source of information.[25]

Enhanced information is insufficient to resolve the problems outlined in chapter 2, because it does not change the features of the current market design that makes it profitable for generators to cannibalise the output of their neighbours. Rather than depending on the altruism of market participants to forego profitable opportunities, a better approach is to design the market so that efficient decisions and profitable decisions are aligned.

3.1.3 Priority access

This variant establishes a queue in the event of bids being tied at the market price floor to determine which generators receive access to the RRP. Market participants can trade to an efficient dispatch outcome using the CRM.

The priority access variant requires new generators to take into account the costs they impose on others when they invest in projects which increase congestion. It addresses the risk that a generators' revenues are cannibalised by another generator that connects after them.

Generators are assigned a queue position that determines their level of priority in the energy market dispatch. A queue position of '0' has the highest priority. Subsequent queue numbers have lower levels of priority. In broad terms, new entrants would have a lower priority than incumbents, but higher priority than generators connecting after them. The mechanism for allocating queue numbers to generators is considered in chapter 5.

The variant achieves efficient outcomes and enables investors to manage access risk. By combining the TQM and CRM, this variant resolves:

a. the dispatch inefficiency that arises if the TQM is applied on its own; and
b. the lack of locational signals/investor certainty if the CRM is applied on its own.

The queue position applies in the energy market when two or more generators have bid at the market floor price (i.e. identical offer prices). The energy market would prioritise the generator for dispatch if it has a more favourable queue position. Figure 12 illustrates this sequence.

Figure 11 Proposed placement of the queue in the energy market dispatch

Source: ESB

24 AEMC, Final Report to the MCE on the Congestion Management Review, June 2008.

25 AEMO, Congestion Information Resource

The queue position does not apply in the CRM. If a more efficient dispatch can be achieved, the CRM provides a mechanism to share profits from the efficiency gain. Participants with a favourable queue position have access to the RRP. Participants with a less favourable queue position can achieve additional revenues via the CRM and be paid at the LMP at the margin. Consequently, we expect the model to give rise to efficient dispatch outcomes.

The variant's key advantage is that it corrects the features of the NEM that make it riskier for investors than other comparable markets. Investors would have more confidence in their congestion studies as projects are not exposed to unexpected curtailment caused by subsequent connections. Other things being equal, this change should lower the cost of capital required by investors, so that the energy transition can be delivered at lower cost.

A critical question is whether new investment is stifled if incumbents are given priority access. Our preliminary view is that it would not deter efficient new entry. Indeed, the 'first in best dressed' dynamic has the potential to accelerate new entry. The access granted by the queue rights reflect the availability of hosting capacity; they adjust in accordance with prevailing network conditions and local generator output. To the extent that there is spare network capacity available at any given time, new entrants can use it. They can also be dispatched via the CRM if there is a lower cost outcome. Each generator is protected from subsequent wealth transfers to future investments, reducing their risk.

A new project may be prepared to absorb higher levels of curtailment in the short term to take advantage of new hosting capacity when it becomes available. But if the new project's business case relied on cannibalising access from incumbents in the medium to long term, arguably it should not be connecting at that location. Put another way, queue positions that have most value are most likely to be in parts of the network that are – or are expected to be – uncongested. This incentivises generators to join the queue in these areas, promoting efficient investment.

The design should carefully consider how it balances the interests of new entrants versus incumbents. Relevant design choices include the role of grandfathering, whether rights should be auctioned, the duration of the rights, and whether the level of congestion faced by priority queue rights holders should be designed to increase over time in line with the efficient level of congestion in the system.

The ESB is considering three alternative methods of allocating access rights, which are first-come first-served, auctions, or some combination. The appropriate choice is a function of several factors, including how valuable the queue rights are, how much capacity is available, and how many generators are seeking access.

3.1.4 Congestion fees

This variant leverages the transmission planning process to determine congestion fees that reflect the available hosting capacity for new generation projects at locations across the grid.

New projects would be subject to congestion fees to provide incentives for their efficient location and design i.e. incentivise developers to minimise the unit connection cost and progress projects of the right design and scale at the right location on the grid. Any congestion fee regime should be based on a clear, transparent process which allows them to identify prospective projects early in the development process.

In operational timeframes, access would be distributed to market participants in the same way as at present. Market participants would have the opportunity to trade to an efficient dispatch outcome via the CRM.

When a new generator connects, it will be required to pay a one-off, fixed fee. Similar to a connection fee, this would be payable in instalments over the life of the project. It can be tailored to support government REZ schemes and would leverage and support the ISP.

Congestion fees will be designed to provide an efficient price signal for investment. New generators would be charged a locational fee based on one of three potential metrics the ESB is considering for calculating connection fees:

1. Estimate the value of access to the RRP
2. Estimate of the total cost of congestion cause by the connecting generator
3. Estimate of the long run incremental cost of future transmission investment as a result of the generator connection.

Each metric would provide an incentive that is aligned with the ISP given the optimal development path is providing targeted augmentation of the national grid which is expanding its hosting capacity in key areas. Generators are incentivised to locate in areas of lower expected congestion because they are charged a lower fee. The risk of inefficient curtailment is lowered because the congestion fees are designed to align profitable investment decisions with the efficient outcome. The efficiency of the signal depends on the accuracy of the central forecasts and the process used to calculate the fees. The alternative metrics and approaches for determining and applying connection fees are discussed further in section 5.4.

However, generators still face a risk (albeit reduced) that their access will be curtailed. A deep-pocketed successor might locate nearby, despite a high congestion fee, with the result that the incumbent's level of access is reduced. This characteristic has led some stakeholders to question whether congestion fees without any corresponding rights will be effective in reducing the cost of capital of new generation projects. Congestion fees based on the long run incremental cost to the network or the change in system-wide congestion would be higher and make inefficient connection less likely. Alternately the priority access model could address this issue.

A fee is known up front and can be set at a level that reflects the externalities associated with the new entrant's location decision. Once the generator has chosen a location and paid the fee, transmission access is allocated in the same way as at present. The sharing of access in a congestion fees variant is a double-edged sword. It may confer more access in the short-term, but it carries the risk that the access will be degraded by later entrants.

It will be necessary to carefully calibrate the scheme to ensure it alleviates problems in the connections regime (by reducing the number of projects seeking to connect in congested parts of the system) rather than exacerbating problems. There is a trade-off between accuracy and simplicity. While congestion fees add a new dimension to the connections process, they also help to ease pressure on the connections regime by discouraging new entrants from connecting in congested locations.

3.2 Integration with jurisdictional schemes

While access within each REZ can be managed through a jurisdictional REZ arrangement, the overall value of a REZ is subject to the broader access to the national grid. Under the current open access regime, participants could choose to connect to the grid at any point outside the REZ. In many cases, that connection could reduce the access available to parties in the REZ and degrade the value of connecting within the REZ. It is also possible that a well-placed connection outside of the REZ could gain preferential access in dispatch. The ways in which transmission access reform supports and strengthens REZ schemes is described in section 2.1.2, and explained in more detail below.

3.2.1 How the operational timeframes components of the hybrid model support REZs

In operational timeframes, the hybrid model supports REZs by ensures that existing transmission infrastructure is used efficiently. A key benefit is the creation of incentives for storage and flexible loads (such as hydrogen) operate in ways that alleviates congestion. This is difficult to do in the status quo, because there is no incentive to do this. As a result, complex contractual arrangements are needed where somebody (such as the TNSP) controls how storage assets are operated at certain times to manage congestion.

At present, if a storage provider or scheduled load helps to alleviate congestion on the grid by soaking up surplus energy, they are not paid for that service. Instead, they face the same RRP as participants located in uncongested parts of the grid. They have no reason to locate where they could provide most value to the grid, nor to operate in ways that soaks up surplus energy.

The business case for storage and flexible loads is hindered by the market design, which does not pay them for the full range of services that they can provide to the grid. Consequently, more government subsidies are required to underpin required investments.

Under the CRM, storage providers and scheduled loads would be paid to provide congestion relief. Storage providers would be able to:

- charge when there is congestion (and the LMP is low)
- discharge when VRE output is low (and there is no congestion, so LMP=RRP).

Flexible scheduled loads would benefit from lower prices inside REZs during periods of plentiful renewable energy.

Access reform is particularly important for generators that are near state boundaries, which often includes REZ generators. If we keep the current market design, generators' ability to supply load outside their own state will be increasingly restricted by flaws in the market design that make it necessary to clamp the interconnectors (i.e. switch them off) to manage counter-price flows. This limitation, which arises because generators are paid the RRP in their own state, even if their output is being used to supply another state, will reduce the anticipated customer benefits arising from interconnector investments.

3.2.2 How the investment timeframes components of hybrid model support REZs

In investment timeframes, the ESB's hybrid model will be designed to support and strengthen State REZ schemes. The ISP framework, which already includes provisions to take account of government policies, would form the link between the access regime and the planning framework. Where a REZ has been identified in the ISP and declared under a jurisdictional scheme, forecast levels of transmission hosting capacity available to REZ generators should be maintained via the access regime. This can be achieved by:

- Priority access – reserving priority queue numbers for a pre-determined MW quantity of new generation capacity that reflects the planned capacity of the REZ
- Congestion fees – by taking planned REZ developments into account in the congestion fee calculations, so that projects wishing to locate in places that undermine the access of REZ generators would face a higher fee.

This would, in effect, reserve a level of capacity for designated REZs. Both variants deliver co-ordinated outcomes across the system as a whole including the parts of the network which are *outside* REZs (since the REZ schemes themselves promote co-ordination within designated zones).

Under the congestion fees variant, fees would be set at levels to encourage/discourage investment in line with jurisdictional schemes. 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. There is flexibility for governments to decide how they would like the arrangements to apply within REZs. Governments could choose whether generators within a REZ are charged a congestion fee, or whether scheme-specific arrangements apply within REZ. A decision to not charge a fee would make REZs relatively attractive compared to non-REZ locations. On the other hand, charging REZ generators would help to recoup REZ scheme costs from the beneficiaries.

Within the priority access variant, governments may decide whether REZ generators should receive priority access over all other generators, or only over other generators that connect after them. The former approach creates strong incentives to invest inside a REZ but may weaken the investment proposition for projects outside REZs. The priority access variant provides a clear mechanism to support the delivery of jurisdictional REZ schemes, since advantageous queue positions can be reserved for REZ generators. As a result, REZ generators will be protected from the financial impact of congestion caused by subsequent connecting generators:

- Foundational REZ generators would receive priority access.
- Generators wishing to connect within a REZ after the initial allocation is exhausted would receive a subordinate queue position.
- Projects wishing to locate in places that undermine the access of firm generators would receive queue numbers that are subordinate to REZ generators, and hence they would not undermine the REZ generators' access.

The value associated with queue positions would increase the attractiveness of REZs relative to alternative network locations. REZs would become an important tool for allocating the queue positions that become available when network upgrades release new transmission hosting capacity. This protection for REZ generators will be firmer than under the congestion fees variant, for reasons outlined in section 3.1.3.

In jurisdictions where State governments have not developed a government-sponsored REZ scheme, the ESB's investment timeframes model would be a stand-alone solution to provide locational signals and manage access risk for investors.

3.3 Implementation considerations

The disadvantages of the hybrid model primarily relate to the risks and costs associated with pursuing a model with novel features. Given its genesis as an effort to engage with stakeholders to design a model that addresses the access reform objectives, the ESB is still working to understand the scale and cost of implementing the hybrid model.

There is a risk that we will uncover an issue that means that the hybrid model does not work as anticipated. More work is required to develop the detailed design and ensure that it does not give rise to unintended consequences.

Certain elements of the model are simpler to implement than others. Elements of the model that affect dispatch and settlements are likely to be more complex and costly than the other elements of the model. The detailed design choices outlined in this paper have significant implications for the implementation task. It is therefore premature for the ESB to attempt to quantify the cost and time require to implement the model. This is scheduled to occur as part of the ESB's draft recommendations (early 2023).

Table 2 Key implementation challenges for the model variants

Model variant	Implementation challenges
CRM	The CRM creates additional complexity in its design considerations and implementation because of the number and type of systems that it affects (bidding, pre-dispatch, dispatch and settlements). The alternative CMM is also a unique model although it benefits from detailed thinking during previous reviews and primarily affects the settlement systems.
Priority access	The implementation challenges relate primarily in its application to affect access outcomes i.e. combining the queue variant with the CRM, and establishing a framework for conducting auctions (if required).
Congestion fees	It will be necessary to carefully calibrate the scheme to ensure it does not add to existing problems in the connections regime. There is a trade-off between accuracy and simplicity. A more bespoke and sophisticated process to determine the fees will provide more accurate locational signals to investors, but also has the potential to add complexity and delay to the connections process. The congestion fees variant has relatively low upfront costs to implement as they are centred on establishing administrative processes to calculate congestion fees. However, there are ongoing administrative costs to deliver these options. As they do not require changes to the dispatch or settlements systems, these elements of the model could be implemented more quickly.

Given that access reform goes to the heart of the market design and affects a number of key market systems, the ESB expects that a significant period of time would be required to implement either of the operational models. Similarly, the priority access variant (which also takes effect in dispatch) would require a multi-year lead time.

The ESB will consider whether there is merit in staging the implementation of the core elements of the model. The elements could be staged as follows:

- enhanced information could be implemented before the CRM,
- if congestion fees are adopted, they could be implemented before the CRM
- if priority access is adopted the CRM could be implemented ahead of the priority access model, but not the other way around.

Given the long life of electricity assets, market participants can be expected to change their investment decision making process in anticipation of the new rules. An extended transition period can also help to smooth the impact of the reforms on market participants' contractual arrangements. As old contracts expire and new contracts are entered, market participants can refine their arrangements in response to the new rules. The CRM has been designed to accommodate existing contractual arrangements as much as possible given the ability of market participants to opt out.

Question for stakeholders

Q1. Should the core elements of the hybrid model be implemented on a staged basis and if so, what factors should inform the decision with respect to staging?

3.4 Preliminary assessment

The assessment criteria for the access reform models were developed in consultation with the Congestion Management Technical Working Group. They 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).[26]

The criteria reflect 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. There is tension between some of the criteria, which reflect the interests of different stakeholder groups. For instance, measures to reduce curtailment risk for today's investors may have the effect of increasing the level of curtailment faced by future investors.

Table 3 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.

26 Section 90F(4)(b) mandates that for South Australian Minister made Rules on recommendation from the ESB, the ESB must be satisfied that the Rules are consistent with the NEO.

Our preliminary assessment of the models against the transmission access objectives is summarised below. The ESB consider that both variants of the hybrid model merit further consideration.

Table 4 Preliminary assessment of models against assessment criteria

Model	**Objective**						
	Efficient investment	Efficient dispatch	Approp. risk allocation	Managing access risk	Effective wholesale competition	Implementation risk	Integration with REZs
Hybrid model w/ priority access	●	●	●	●	●	○	●
Hybrid model w/ congestion fees	●	●	◐	◐	●	◐	●

Key

● *Fully achieves the transmission access objective*

◐ *Partially achieves the transmission access objective*

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

The key advantage of the priority access variant is that it corrects the features of the NEM that make it riskier for investors than other comparable markets. New entrants have proceeded on the basis that they can cannibalise the access of projects that are already there. Investors have suffered as their projects are displaced by newer ones – sometimes only a short time after connecting.

4 Detailed design choices - operational timeframes

4.1 Overview of proposed approach

The CRM is an adjunct to the existing energy market. It introduces a new market that can achieve a more efficient dispatch than today's energy market. Participants would continue to submit bids into the energy market, but they have an opportunity to increase profits by sharing incremental efficiency gains in the CRM. It unlocks a new market for congestion management and recognises the value that storage and scheduled load can provide to the energy system.

The CRM design aligns with a fundamental principle of any congestion model in the separation of 'access' and 'physical dispatch'.

- Access refers to the participant's access to the RRP.
- Physical dispatch refers to the final physical dispatch (generation and load).

Today's energy market determines both access and physical dispatch at the same time i.e. a generator has access to the *regional* reference price based on its physical dispatch. But physical dispatch is a local clearing process that balances supply and demand at each node. This disconnect leads to distorted bids that do not reflect a participant's costs. Participants want access to the RRP because contracts are typically referenced to it. NEMDE cannot dispatch cost efficiently if bids are distorted.

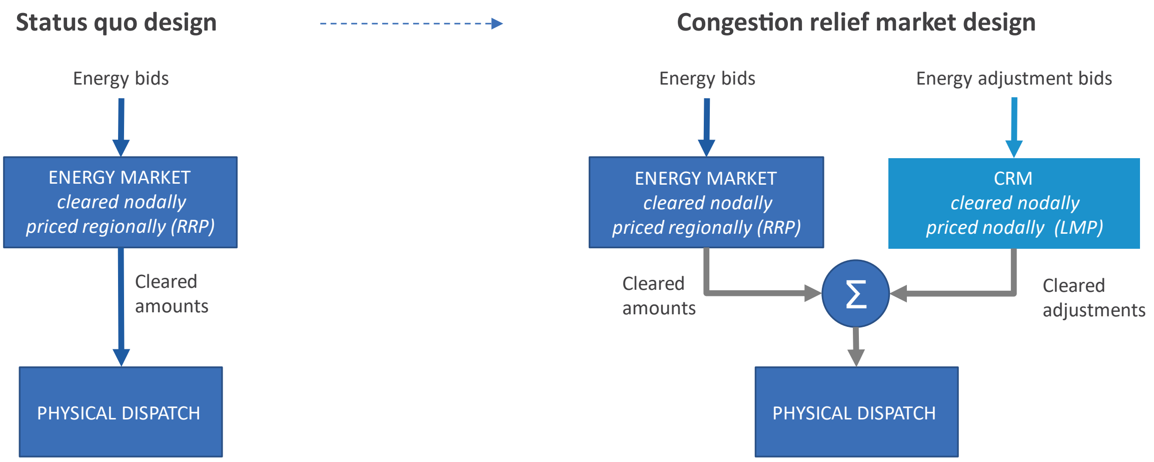
The CRM design separates access and physical dispatch because it allows for an incremental dispatch that is priced at the LMP. It comprises:

- the current energy market (NEM dispatch)
- a dispatch adjustment market (CRM).

Participation in the CRM is voluntary. A generator not participating in the CRM is dispatched according to the energy market dispatch, as today.

Figure 13 illustrates how participants would submit two sets of bids: to the energy market and the CRM. AEMO would incorporate the two optimisations into the NEMDE dispatch process. Participants are priced at the RRP for outcomes of the energy market and at the LMP for CRM adjustments. The CRM incentivises cost reflective bidding.

Figure 12 Market architecture moving from status quo to a future CRM design



Note: the diagram deliberately simplifies the NEM dispatch. It is noted that energy and FCAS bids must be co-optimised in the same dispatch.

AEMO is investigating the technical design to achieve an explicit opt-out from the CRM. Ideally, those participants would not need to adjust their bidding systems and could continue to submit a single set of bids that only apply to the energy market. They would not have any CRM adjustments and would forgo any incremental profits.

4.1.1 Key concepts

Design choices in this chapter often refer to RRP and LMP. Box 1 provides a recap of these concepts.

Box 1 Definitions of RRP and LMP

Regional reference price

The RRP is the spot price at which the energy market clears in today's market design. It is specific to its regional reference node (RRN). It represents the change in the cost of dispatch if one more MWh of load is needed to be supplied at the RRN.[27]

Locational marginal price

The LMP is specific to each node of the network i.e. it is the change in the cost of dispatch if one more MWh is supplied at that location. A node typically refers to a single generator or scheduled load.

If the node is constrained, the LMP is linked to the marginal costs of all the constraints affecting the node.

Generally, if only one constraint is binding, a generator with a lower constraint coefficient will receive a higher LMP and would be more likely to be dispatched in the CRM for the same set of bids.

The LMP is defined as:

$$\text{LMP} = \text{RRP} - \textstyle\sum_{\text{constraints}} \text{marginal cost of constraint} \times \text{constraint coefficient}$$

Refer to footnote for mathematical expression and definitions.[28]

The LMP is location specific to each node because the constraint coefficients are unique to each constraint.

LMPs are not a peculiar feature of electricity markets. They reflect competitive commodity market pricing. In most markets, suppliers are paid a hub price for their product, but also have to pay for transport to the hub. Or they can receive a local price at the farm, factory or mine gate, and the buyer pays for transport.

The NEM's existing design is inconsistent with other commodity markets: suppliers don't pay for transport to a hub, and yet get paid the hub price (adjusted for loss factors). If the node is unconstrained in the dispatch, the LMP is equal to the RRP (ignoring loss factors) i.e. transport prices are zero.

In the CRM design, revenue comprises two components with energy dispatch (G_{NEM}) paid at the RRP and any incremental CRM dispatch (G_{ADJ}) (which can be positive or negative) paid at the LMP. The formula (next page) ignores the effect of losses for simplicity.

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27 Refer to clause 3.9.2 (d) for the formal definition according to the National Electricity Rules.

28 The mathematical calculation of LMP is as follows. For node n which has dispatchable resources at its location its nodal price is $LMP_n = RRP + \sum_{k\ in\ network\ constraints} a_{k,n} \times \lambda_k$ Where λ_k is the shadow price of the k[th] network constraint and $a_{k,n}$ is the coefficient of the dispatchable resource at node n in constraint k. The congestion price for the kth constraint, $\mathrm{CP_k} = -\lambda_k$. Note that λ_k will be negative for *a* '<=' constraint as an increase in the RHS by one unit will reduce the objective function (total of dispatch costs) whereas λ_k will be positive for *a* '>=' constraint as an increase in the RHS will increase the objective function.

Revenue = G_{NEM} x RRP + G_{ADJ} x LMP

Where

G_{NEM} MWh dispatch from the energy market

G_{CRM} MWh dispatch from the CRM market

G_{ADJ} MWh adjustments = $G_{CRM} - G_{NEM}$.

If a participant opts out, $G_{CRM} = G_{NEM}$ so $G_{ADJ} = 0$ and revenue is defined as it is now: G_{NEM} x RRP.

The participant will still profit if its physical dispatch is lowered assuming that it bids at cost in the CRM. If $G_{ADJ} < 0$, this must mean its LMP is less than its costs. Since $G_{ADJ} < 0$ and *LMP < cost*, then $G_{ADJ} \times (LMP - cost) > 0$.

4.1.2 Integration with the design choices in the investment timeframes

The hybrid model proposes two key variants in the investment timeframes:

- priority access
- congestion fees.

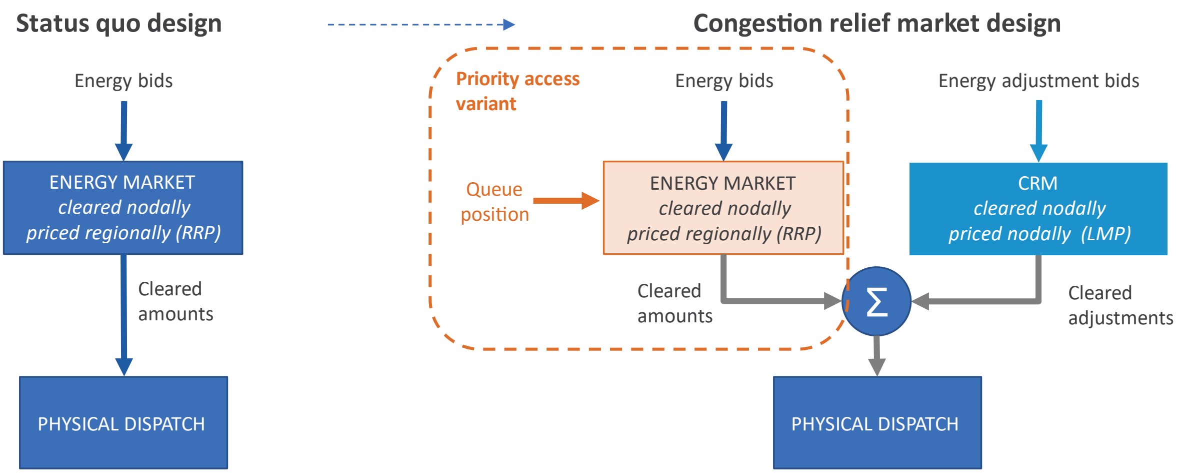
The priority access variant has a direct impact on dispatch outcomes in operational timeframes. In the CRM design, access is determined by the energy market. 'Priority access' means priority in the energy market. The algorithm used to determine energy dispatch must be re-designed to dispatch according to the priority order that is established in the investment timeframes.

The congestion fees variant does not directly affect dispatch systems given there is no priority access, and the existing energy dispatch design is used.

Chapter 5 provides more detail on design choices for both variants.

This section outlines how priority is introduced to the dispatch algorithm in the energy market via a queue position. Refer to Figure 14. NEMDE would need to be modified to incorporate the new inputs and logic associated with the variant. Priority does not apply to the CRM component of the design.

Figure 13 Priority access variant incorporated into the CRM design



A queue position of '0' has the highest priority. Subsequent queue numbers have lower levels of priority. New entrants have a lower priority than incumbents, but higher priority than generators connecting after them. All generators existing at the time of implementation would share equal, highest priority i.e. a queue position of '0'.

Priority dispatch is the same as today's dispatch, except where two or more generators are bidding at the market floor price and competing for dispatch. In this case, the higher priority generator is dispatched in preference to the lower priority generator. The energy market algorithm would prioritise dispatch in the following order:

- priority order based on a queue position.
- where generators also share the same queue position, then according to constraint coefficients (as explained in section 2.1.3).

There are complexities to implementing these principles into NEMDE. NEMDE's optimal dispatch has broader considerations than just constraint coefficients. Chapter 5 explores the preliminary options to give effect to this design principle in practice.

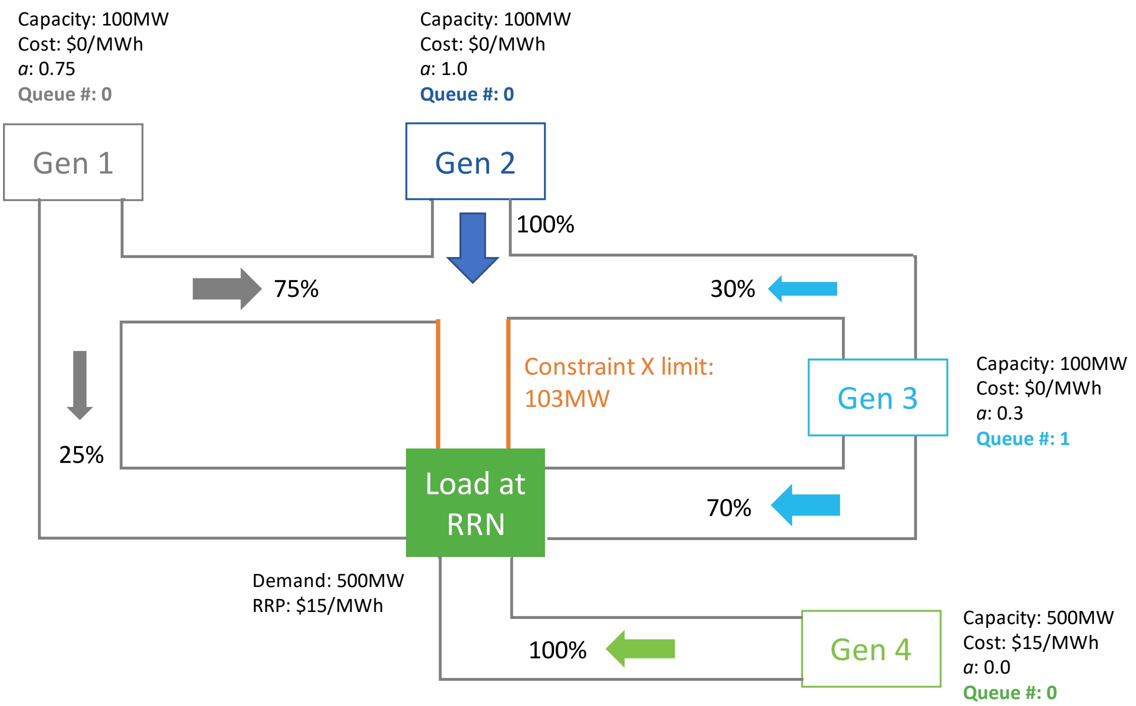
The queue position does not apply in the CRM. It does not interfere with achieving an efficient final dispatch through the incremental adjustments of the CRM.

Participants with a favourable (lower) queue position have greater access to RRP in the initial energy market. They can also benefit from profit increases available in the CRM.

Participants with a less favourable (higher) queue position can still be physically dispatched. But they are more likely to be dispatched at LMP at the margin via the CRM rather than at RRP.

A worked example of the integration of priority access and the CRM design is provided below. Figure 15 shows a simple illustrative scenario ignoring loss factors.

Figure 14 Illustrative figure showing queue positions



α = constraint coefficient

For simplicity:

- Gen 1, Gen 2 and Gen 3 are located behind the constraint. Gen 4 is unconstrained. The arrows show the power flows through the looped network according to their constraint coefficients.
- Gen 1, Gen 2 and Gen 3 are assumed to be variable renewable energy generators with short run marginal costs of $0/MWh. Gen 4 offers $15/MWh.
- Gen 1 and Gen 2 are assumed to be incumbent generators with queue position ‘0’. Gen 3 is a new entrant assigned queue position ‘1’.

Energy market and CRM, with and without priority access

Assume all three constrained generators bid at the market floor price (-$1000/MWh) in the energy market to maximise their access to RRP. They bid cost reflectively in the CRM. The table below summarises their costs and bids.

Table 5 Generator bids for the energy market and CRM

Unit	Cost *$/MWh*	Bid – energy market NEM *$/MWh*	Bid – CRM *$/MWh*
Gen 1	0	-1000	0
Gen 2	0	-1000	0
Gen 3	0	-1000	0
Gen 4	15	15	15

Energy market without priority access

In the status quo, the energy market would dispatch on a combination of bid price and constraint coefficients:

- Gen 3 is fully allocated access of 100MW (coefficient 0.3)
- Gen 1 is partially allocated access of 97MW (coefficient 0.75)
- Gen 2 is not allocated access (coefficient 1.0)
- Gen 4 provides the remaining balance of 303MW at the RRN (coefficient 0.0).

Energy market with priority access

With the priority access variant, the energy market would dispatch on a combination of bid price, queue position and constraint coefficients. The queue position applies as follows:

- Gen 1 – 3 are all bidding at the market floor price into the energy market. Dispatch must take account of the access priorities.
- Gen 1 and 2 have higher priority than Gen 3 so the former two are dispatched preferentially.
- Gen 1 and 2 have the same priority so dispatch is based on the existing market design, where the lower coefficient is dispatched in preference. Gen 1 is dispatched first with Gen 2 next.

As a result, the priority access variant would dispatch in the following order of priority:

- Gen 1 is fully allocated access of 100MW (queue position 0, coefficient 0.75)
- Gen 2 is partially allocated access of 28MW (queue position 0, coefficient 1.0)
- Gen 3 is not allocated access (queue position 1, coefficient 0.3)
- Gen 4 provides the remaining balance of 372MW at the RRN (coefficient 0.0).

CRM with or without priority access

In the CRM, the physical dispatch is based on the lowest cost outcome. It does not factor in queue position. In order of priority:

- Gen 3 is fully physically dispatched at 100MW
- Gen 1 is partially dispatched at 97MW
- Gen 2 is not physically dispatched
- Gen 4 provides the remaining balance of 303MW.

The CRM adjustments are calculated with reference to the energy market outcomes (either without priority access or with priority). The table below summaries the financial outcomes.

Table 6 Financial outcomes with and without priority access

Unit	Total cost $		Energy market profit $		CRM profit $		Total profit $	
Option	*Without priority*	*With priority*	*Without priority*	*With priority*	*Without priority*	*With priority*	*Without priority*	*With priority*
Gen 1	0	0	1,460	1,500	0	0	1,460	1,500
Gen 2	0	0	0	420	0	140	0	560
Gen 3	0	0	1,500	0	0	900	1,500	900
Gen 4	4,540	4,540	0	0	0	0	0	0
Total	**4,540**	**4,540**	**2,960**	**1,920**	**0**	**1,040**	**2,960**	**2,960**

With or without priority access, the CRM design enables an efficient dispatch outcome. Costs are equivalent at $4,540.

Without priority access, the incumbents' profits (Gen 1 and Gen 2) are exposed to the risk of future congestion caused by new entrants (Gen 3). Gen 1 receives profits of $1,460 as it is partially cannibalised by Gen 3. Gen 2 receives no profits and is fully cannibalised by Gen 3.

With priority access, the incumbents' revenues and profits are protected against the new entrant. Profits for Gen 1 and Gen 2 in the energy market are consistent as if Gen 3 had not entered the market. The CRM allows for additional profits for all three generators. Gen 1 receives total profits of $1,500 (as the marginal generator) and Gen 2 receives profits of $560. Gen 3 is still profitable at its LMP.

A key design choice relates to the choice of locational signal in the investment timeframes (with priority access or congestion fees without priority access). Chapter 5 provides more detail on the design choices for both variants.

4.2 Key design choices

This chapter proposes choices for the CRM design that would apply irrespective of the variant between priority access and congestion fees.

There are two components to the CRM design:

- existing energy market
- new CRM.

The CRM is a new market with improved incentives for cost reflective bidding. Key questions for the CRM component relate to its implementation and technical feasibility. The ESB is working closely with AEMO on these matters.

The Directions Paper seeks feedback on design choices for the energy market. It is an existing component but it is affected by the creation of a CRM including participants' bidding incentives.

Table 7 Design choices for the CRM design

Section	Description	Design choice
4.2.1	To confirm the scope of participants affected	The proposed scope of participants considers: • scheduling status i.e. scheduled, semi-scheduled or non-scheduled • whether the market participant is a generator, load or storage • whether the market participant is connected to transmission or distribution.
4.2.2	To improve outcomes from today's market	Design choice to buffer revenue volatility and share congestion risk by rounding constraint coefficients.[29]
4.2.3	To respond to arbitrage opportunities between the energy market and CRM	Design choices for scheduled and semi-scheduled generation to: • prevent bidding behaviour that would lead to wealth transfers to generators that would not be incentivised in today's energy market • facilitate risk management for generators contracting with retailers and other market customers.
4.2.4		Additional design choices for storage that consider storage when acting as a generator and as a load.
4.2.5	To calculate the RRP	Alternative calculations based on: • marginal cost of an additional unit of load at the RRN in the energy market, as it is currently calculated; or • marginal cost of an additional unit of load at the RRN in the CRM.
4.2.6	To calculate settlements	Alternative calculations based on: • metered output settled at RRP • metered output settled at LMP

Appendix C provides worked examples that illustrate the choices for the CRM design.

4.2.1 Parties subject to the arrangement

In general, maximising who can participate in the CRM is likely to increase dispatch efficiency. It enables the broadest range of resources to trade congestion relief.

There are a few dimensions to consider for the scope of market participants affected:

- scheduling status i.e. scheduled, semi-scheduled or non-scheduled
- whether the market participant is a generator, load or storage
- whether the market participant is connected to transmission or distribution.

Each are considered in turn.

29 The coefficients of generator terms in the LHS of the constraint equations used in the NEM dispatch.

Scheduling status

As scheduled and semi-scheduled market participants bid into the energy market, it is proposed that they could participate in the CRM.

Non-scheduled market participants do not bid into the energy market and so cannot participate in the CRM. They would automatically be settled at the RRP, as they are now.

Generator, load and storage

The CRM would be open to all (scheduled and semi-scheduled) generators, scheduled load and scheduled storage. Scheduled load and storage are likely to be important beneficiaries of the CRM and contributors to more efficient dispatch.

Transmission or distribution connected

All scheduled and semi-scheduled generators, scheduled load and storage would be able to participate, regardless of whether they are connected at the transmission or distribution level. We have not identified any reasons to exclude distribution connected market participants.

Questions for stakeholders

The ESB has outlined the proposed parties that would be subject to the reform arrangements. These are consistent with the design choices discussed in Section 5.5 (Detailed design choices - investment timeframes).

Q2. Do you agree with the proposed scope of market participants included in this access reform?

Q3. Should different treatments apply to any particular categories of market participant?

4.2.2 Alternative distributions of congestion risk in the energy market

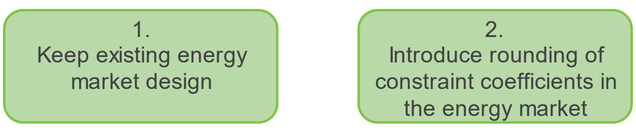
The design choice between congestion fees and priority access has a significant impact on the allocation of congestion risk. This is addressed in Chapter 5.

There is an additional opportunity to redistribute congestion risk that would apply in parallel with the investment timeframe models. It is designed to address the issue that dispatch outcomes in the face of congestion are a function of complex interrelated technical factors, which means they are opaque, volatile and hard to predict.

In today's energy market, marginal differences in constraint coefficients can lead to revenue volatility and investor uncertainty. New entrants may locate in the network and secure a marginally more favourable coefficient. New entrants should be encouraged in any competitive market but incumbents are bearing the cost of congestion caused by that new entrant.

Figure 16 introduces a design choice in response for re-distributing congestion risk.

Figure 15 Design choices for distributing congestion risk in the energy market



A worked example of rounding constraint coefficients is provided in Appendix C. Refer to Box 4.

Option 1 keeps the existing energy market design in terms of its calculation of constraint coefficients. The energy market dispatch would continue to prioritise generators based on marginal differences between coefficients.

Option 2 rounds coefficients to 1 or 2 decimal places in the energy market. Participants with different coefficients (e.g. Gen A has 0.7935 and Gen B has 0.7512) could have common coefficients after rounding to 1 decimal place (0.8). This rounding could, in some circumstances, have a marked change in dispatch outcomes. With slightly different coefficients, Gen B might be fully dispatched and Gen A might be dispatched at a low level or not at all. With both coefficients rounded to 0.8, they share the available dispatch equally i.e. in proportion to the quantity of the relevant bid.

Rounding the coefficients partially socialises congestion risk and represents a 'buffering' of volatile outcomes. In the case of a REZ, participants are likely to have similar but not identical coefficients for constraints applying remotely from that REZ. This option promotes the socialisation of congestion risk between these parties locating in the same area. There would be an increase in the instances of tied bids, which would be resolved according to AEMO's tie breaking constraint and may increase NEMDE solve times.[30]

This rounding would apply to the energy market component of the CRM design. It would not apply rounding to the CRM i.e. it does not interfere with achieving a more efficient dispatch through CRM adjustments. In the example above, whilst Gen A and Gen B would be dispatched equally in the energy market, Gen B would be preferentially dispatched in the CRM.

Table 8 Description of design choices for the distribution of congestion risk

Option	Description	Pros	Cons
1. Keep existing energy market design	Retain the existing energy market dispatch design.	This option preserves the status quo with which market participants are familiar. Market participants would continue to place reliance on congestion studies and other locational signals to assess their congestion risk.	The uncertainty of forecast revenue leads to higher costs of capital that are passed to consumers. Congestion risk applies also to future REZ developments where new entrants can locate outside a REZ and affect financial and dispatch outcomes for those parties within the REZ.
2. Rounding constraint coefficients in the energy market	Rounding the coefficients in the energy market to 1 or 2 decimal places.	This option partially mitigates the downside risk of future congestion which has benefits for investor confidence. It buffers the revenue volatility of congestion risk between participants that have similar coefficients. If new entrants locate in the network and secure a marginally more favourable coefficient, the resulting wealth transfers will not be as severe. In the case of REZs, generators in a similar location are likely to have similar coefficients. This proposal allows the	It creates wealth transfers between incumbent generators. Generators that currently enjoy the benefits of marginal differences in coefficients would have reduced revenues. This option is a partial solution to the risk of future cannibalisation. The risk remains that a new entrant could still displace existing generation if it has a coefficient difference of more than 1 decimal place. Rounding coefficients will lead to more instances of tie-

30 Tied bids for blocks of energy are dispatched in proportion to the MW sizes of the respective bands. Refer to AEMO Schedule of Constraint Violation Penalty Factors, November 2017, p.24 https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/schedule-of-constraint-violation-penalty-factors.pdf

Option	Description	Pros	Cons
		congestion risk to be shared between these parties, rather than differentiating 'winners and losers' on the basis of potentially small differences between coefficients. If the priority access variant is introduced, rounding coefficients then addresses the residual risk that participants are exposed to congestion risk within their same band of queue positions. The benefits are highest if there are a large number of parties within the same band.	breaking. Technical plans to accompany this design choice will need to be developed and to ensure that the increased prevalence of tied bids does not inhibit the system solve time. If a secure dispatch cannot be achieved with rounding, a subsequent trade-off decision will be needed between relaxing the rounding or relaxing an alternative constraint. It may lead to settlement deficits if the energy market 'violates' constraints due to rounding. It is unlikely to cause a material deficit but rules will need to be drafted to handle any settlement deficits.

Questions for stakeholders

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

Q4. Do you agree with the assessment of risks and opportunities for these design options?

Q5. What is your preferred option and why?

4.2.3 Arbitrage opportunities between the energy market and CRM for out-of-merit generators

The CRM introduces a new market that can achieve a more efficient dispatch beyond today's energy market i.e. inefficiencies in the energy market can be adjusted. This could mean that a generator initially dispatched in the energy market is not actually physically run, with their energy replaced by a cheaper alternative. The generator is rewarded for its contribution to more efficient dispatch and is paid based on the difference between RRP and LMP.

This reward is justified if the generator would have been inefficiently dispatched in today's market. But this can only be the case for "in-merit" generators, with operating costs below RRP. Out-of-merit generators, those with costs higher than RRP, would not seek to be dispatched in the first place, and it is arguable that they should not be receiving this reward.

The basic CRM design does not differentiate between in-merit and out-of-merit generators. The latter have a new opportunity to receive this payment, despite not contributing to dispatch efficiency. It is a design choice to allow or avoid payments to these out-of-merit generators. If payments are to be avoided, the CRM must be designed to distinguish between these two categories of generator.

For generators, the issue arises where $LMP < RRP < cost$:

- the generator's costs are greater than the RRP for a particular dispatch interval ($RRP < cost$)
- the generator has a positive coefficient in a binding constraint ($LMP < RRP$) (assuming it is only participating in a single binding constraint).

In today's energy market, access and physical dispatch is determined at the same time. As a result:

- If a generator's *cost < RRP*, the generator wants access to the RRP.
- If a generator's *cost > RRP*, it does not want access to the RRP because it will incur the cost of physical dispatch.
- Generators only seek access to RRP if they are "in-merit" i.e. *cost < RRP*.

In the future CRM design, access to the RRP is decided by bids into the energy market. A generator does not face physical costs to generate until the adjustments of the CRM are finalised. As a result, if we do not make a design choice to modify this aspect of the CRM, the following outcomes could arise:

- Generators can adjust their bids to secure access to the RRP i.e. where *LMP < RRP*, both in-merit and out-of-merit generators may strategically bid to the market floor price.
- Generators can opt into the CRM and submit cost-reflective bids. The CRM engine will dispatch a generator if its bid is less than the LMP. The out-of-merit generator will not be dispatched in the CRM when it submits its cost-reflective bid.
- The out-of-merit generator is paid RRP for its energy dispatch but then has to repay LMP because it is not dispatched in the CRM. Its monetary profit is (RRP – LMP) x G_{NEM}.
- Under these circumstances, the constrained out-of-merit generators do not incur the physical costs of generation but secured a financial gain through its access to RRP in the energy market.

The downsides are:

- Access to the RRP for in-merit generators is diluted compared to the status quo. They are liable to get a lower energy dispatch due to out-of-merit generators using part of the available transmission capacity.
- New generators – including storage – may seek locations which are favourable for obtaining access to the RRP, with little or no incentive to physically dispatch. This is not an efficient use of investment resources. Even short-duration storage can earn an ongoing monetary profit using the strategy described because it is never required to physically discharge and so can continue to be dispatched in the energy market indefinitely.

Refer to Table 9 for a comparison of the bidding incentives.

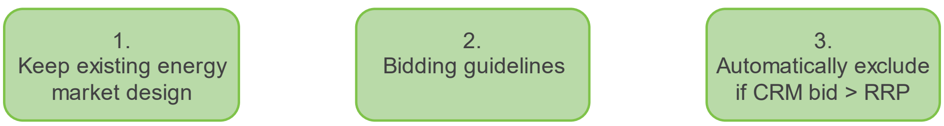
Table 9 Arbitrage bidding in the energy market – scheduled and semi scheduled generation

Coefficient	Merit position	Bidding incentives $/MWh		
		Today's energy market	Future energy market	Future CRM
Positive – causing congestion	*In-merit*	-$1000	-$1000	at cost
	Out of merit	at cost	-$1000	at cost

Figure 17 outlines the design choices to address wealth transfers to out-of-merit generators as a result of these arbitrage opportunities.

The out-of-merit issue can be harder to identify for storage (i.e. hydro, pumped hydro, batteries) because they bid based on the marginal value of their stored energy and contract positions. This changes constantly as energy storage depletes or is replenished, together with changing expectations of future spot prices. The next section 4.2.4 recognises the complexity of identifying and addressing this issue related to storage and proposes additional solutions.

Figure 16 Design choices to address issues with out-of-merit generators



Option 1 keeps the existing energy market design. There are no additional rules or interventions applied to exclude participant bids that would have previously been identified as 'out of merit'.

Option 2 updates the bidding guidelines to ensure it captures the new risks and opportunities of the CRM design. It would outline the principles for bidding behaviour to deter participants previously identified as 'out of merit' from applying the arbitrage opportunity to seek financial gain. It would leverage the existing regulatory framework and rely on market participants to update their internal processes and controls in response to these guidelines. Compliance would be monitored by the AER.

Option 3 is an automated measure to introduce a new logic rule into the energy market dispatch that would filter out inconsistent bids (between the energy market and CRM) deemed to be from out of merit generators. A rule would be applied such that, if a generator was bidding in the CRM above forecast RRP, its bid into the energy market would be excluded unless it was consistent with its CRM bid.

Table 10 Description of design choices in response to arbitrage opportunities for out-of-merit generators

Option	Description	Pros	Cons
1. Keep existing energy market design	Accept that the energy market in the CRM design may no longer identify out of merit generators that have previously been excluded from the energy market dispatch.	An efficient dispatch is still achieved (assuming that bids in the CRM are cost reflective). It minimises market interference and represents the simplest option for the market bodies to implement.	There are wealth transfers away from in-merit to out-of-merit generators. Out-of-merit generators may be incentivised to stay in the market (beyond an efficient retirement date) because of their financial gains from the energy market. There is a limited risk that new entrants may enter the market to gain access to the RRP in the energy market without seeking to be physically dispatched i.e. it would have a financial gain in the energy market and its CRM adjustments would unwind the initial outcome to avoid physical dispatch.
2. Bidding guidelines	Modify the bidding guidelines to prohibit bidding behaviour that would give out-of-merit generators financial gains in the energy market with no intent of being physically dispatched. The AER would be responsible for monitoring bidding to identify anomalies which could refer to a combination of data points e.g. historical bidding record, comparison of bids into the energy market and CRM or inferred costs.	This option leverages existing regulatory frameworks including rules for bidding behaviour and a monitoring function by the AER. The risk of regulatory investigation may be sufficient to ensure market participants introduce internal processes and controls to manage regulatory compliance.	Some instances of out-of-merit bidding may be difficult to identify i.e. for a generator where $LMP < bid_{CRM} < RRP$. Bidding anomalies are particularly challenging to identify for energy-limited plant e.g. hydro, pumped hydro and batteries. The next section 4.2.4 recognises this challenge and introduces modified design choices for storage. The AER would incur costs for the implementation and ongoing monitoring of new bidding rules.

Option	Description	Pros	Cons
3. Automatically exclude if the CRM bid > RRP	Exclude out of merit generators from the energy market dispatch based on the participant's bids in the CRM relative to the RRP. Where *CRM bid > forecast RRP*, a generator's bid would need to be consistent in the energy market and CRM. It is implicitly assumed that generators bid at or close to cost in the CRM i.e. the CRM bid is a proxy for cost.	It is a straightforward rule to define and provides a first filter to exclude bids that are more clear-cut in terms of being out of merit. There are ways that a participant could strategically bid to avoid this automated filter but the risks associated with strategic bidding (including the potential that an out-of-merit generator may be dispatched) could reduce the likelihood and materiality of residual wealth transfers.	While its definition is clear, there are technical challenges which will be considered as part of the implementation plan.. RRP is not known at the time of the energy market dispatch, only the RRP from the previous period i.e. exclusions may need to apply based on RRP forecast in the previous dispatch interval. The solution is incomplete in the face of strategic bidding. Out-of-merit generators could respond by amending their CRM bids below RRP. So long as their bids are still above their LMP, they will not be physically dispatched. Note that this option could be implemented in parallel with Option 2 in order to monitor and investigate anomalous bidding behaviour.

Questions for stakeholders

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

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

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

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

4.2.4 Treatment of storage acting as a generator and as a load

A key benefit of a congestion model is to reward storage for its services in relieving congestion. The CRM unlocks a new market for this congestion relief and provides a clear price signal for its value. The CRM creates opportunities for higher price spreads for storage to charge at its LMP and facilitates new contract arrangements between storage/scheduled load and congested parties.

Appendix C Box 3 provides a worked example of financial and dispatch outcomes for storage in the CRM.

The objective of the CRM design is to ensure that storage located behind a binding constraint has incentives to:

- relieve congestion by acting as a load i.e. charging
- avoid exacerbating congestion when acting as a generator i.e. discharging.

Figure 18 and Figure 19 highlight design choices for storage. The choices assume the following:

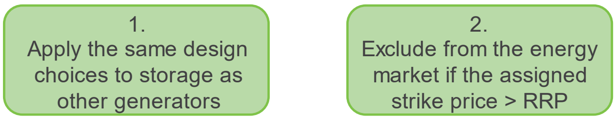
- When storage is acting as a generator, it is:
  - unlikely to want to dispatch in the energy market when the RRP is low
  - likely to want to dispatch in the energy market when the RRP is high e.g. during a major, non-credible outage of generation or transmission plant.
  - likely to want certainty of access to RRP when it is high, in order to back any forward contracts it has written e.g. cap contracts.
- When storage is acting as load, it is:
  - likely to want to charge at the lowest price available i.e. where LMP<RRP, it will prefer to charge through the CRM rather than through the energy market
  - unlikely to need access to the RRP to back its contract arrangements, so long as LMP < RRP.

Under the CRM design, storage can strategically bid into the energy market and CRM for monetary profit without improving the dispatch efficiency. It can achieve this both as a generator and as a load. The design choices are intended to align the incentives for storage with the congestion relieving benefits for the system as a whole.

Storage acting as a generator

Section 4.2.3 discussed the 'out-of-merit' issue for generators. The design choices may not sufficiently address the issue for storage. In particular, battery storage, with its smart bidding algorithms and fast ramp rates, could take advantage of the arbitrage opportunities resulting in wealth transfers away from in-merit generators. Figure 18 proposes an additional option for storage.

Figure 17 Design choices for the treatment of storage as a generator



Option 1 would treat storage with the same design choices as for other generators i.e. design choices of 'do nothing', 'bidding guidelines' and 'automatically exclude if CRM bid > RRP' would apply equally to storage with no further adaptations.

Option 2 assigns a "strike price" which determines whether the storage unit is in-merit. When acting as a generator:

- If RRP is higher than the assigned strike price, it is in merit.
- If RRP is lower than the assigned strike price, it is out of merit, and its CRM bid must be consistent with its energy market bid.

In recognition of the need for storage to back its contracts, a strike price could be assigned e.g. at $300/MWh similar to an over the counter cap contract.

There may be instances when RRP is above the strike price for an extended period of time. The assigned strike price would not prevent the storage unit from taking advantage of the arbitrage opportunities unless an additional restriction was applied. A complementary variant would be to assign an availability profile for storage.

For example, a 2-hour storage unit might be assigned an availability of 2 hours over the morning peak and 2 hours over the evening peak. The storage operator could nominate an availability profile that is consistent with its storage capability.

Storage participants are already required to provide the 'daily energy constraint' as an input to daily bidding files. This could be adapted to apply an automated rule in the energy market.

Table 11 Description of design choices for storage as a generator

Option	Description	Pros	Cons
1. Apply the same design choices to storage as other generators	Apply the same design choices to storage as other generation.	It is a simpler approach and applies consistency across all technology types.	The design choices (as applied to other generators) may be insufficient to prevent or detect strategic bidding by storage that leads to wealth transfers away from in-merit generators.
2. Assign a strike price for storage in the energy market	A "strike price" would be nominated for storage to determine whether it is in merit. The storage unit would receive access to RRP when RRP exceeds the strike price. An additional option could be applied to limit the storage unit's access to the RRP based its availability profile i.e. in the event of a high RRP that exceeds the strike price for an extended period of time, access to the RRP would also be limited by its availability profile.	This variant addresses the key commercial risk where storage generation is constrained off and does not receive access to RRP at a time of extreme RRP e.g. during a major, non-credible outage of generation or transmission plant. It is designed to support locational signals for storage to locate in REZs and/or congested areas, because it continues to allow the participant to hedge/insure its forward contracts.	It could adversely affect the ability of storage to offer certain types of contracts such as virtual storage contracts. Storage is likely to want to pump or charge at the lowest prices during a day and generate or discharge at the highest prices. Sometimes the highest daily prices could be much lower than a nominated strike price. It introduces further complexity for implementation (including operation and settlement).

Storage acting as a load

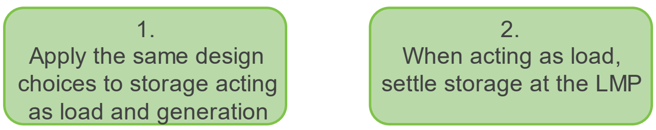
The out-of-merit issue applies in a similar way to storage acting as load.

There may be circumstances when a storage unit is located in front of a constraint, leading to an LMP that is higher than RRP. Storage (as load) could bid a quantity into the energy market, at the market price cap, that exceeded its genuine intent to consume. It could then bid its true load into the CRM. After settlement for the energy market and CRM are netted out, it would be paid the difference between LMP and RRP on the quantity difference between its energy market bid and its CRM bid.

For example, if LMP = $100/MWh and RRP = $60/MWh, the storage could bid 10MW into the energy market but only 3MW into the CRM; the latter is "dispatched" and consumed. It pays RRP on its 3MW of consumption – as it would today – but also receives a financial credit of (100 – 60) x (10 – 3) = $280 every hour that the strategy continues.

Figure 19 outlines the two design options for storage as load.

Figure 18 Design choices for the treatment of storage as load



Option 1 allows storage to have access to the RRP when acting as load. The equivalent design choices for storage as a generator (discussed in previous sections) would apply to storage as load.

Option 2 proposes to exclude storage from the energy market when acting as load. It would be able to participate in the CRM. It is important to distinguish that this option allows storage to:

- retain access to the RRP as a generator
- only charge at the LMP when acting as load.

Contract arrangements for storage are likely referenced to the RRP. Under this option, storage would charge in the CRM at its LMP but retain its ability to have access to the RRP and hedge its liability in the energy market as a generator.[31]

Table 12 Description of design choices for storage as load

Option	Description	Pros	Cons
1. Apply the same design choices to storage acting as load and generation	This option applies the same design choices for storage as a generator to storage as a load. Storage as load would retain its access to the RRP.	It applies consistency across all technology types.	The design choices may create complexity when addressing the out-of-merit issues. It does not provide a simple solution to the out of merit issue for storage as load.
2. When acting as load, settle storage at its LMP	When storage is acting as load, it would not be provided access to the RRP i.e. it would not be allowed to bid in the energy market. It would be able to participate in the CRM. This rule is not relevant to storage acting as a generator.	It provides a simple solution to resolve out-of-merit issues for storage as load. It also meets the primary commercial objective to consume energy when prices are low i.e. the LMP will generally be less than the RRP so it retains the upside risk. It is low risk for storage since its contracts would be related to discharging as a generator rather than charging as load. Storage would retain access to RRP as a generator. It is unlikely to need access to the RRP when acting as load. It may encourage liquidity in the CRM if storage is trading at LMP. It will increase the value for generators participating in the CRM.	Storage as load would not be able to hedge the risk associated with exacerbating a constraint (ie, when *LMP > RRP*). In practice, this issue may be rare. The CRM is voluntary. Storage may find it difficult to charge at LMP if there is insufficient generation participating in the CRM. This is likely to be highest risk in the short term immediately after the CRM system is implemented. It relies on other market participants having updated their bidding and dispatch systems. It requires a reframing of the CRM that differs from the design of its original proponents i.e. bids for storage as generation can be submitted into the energy market and/or CRM but bids for storage as load will only be submitted into the CRM.

31 If the storage provider adopts the new participant category of a bi-directional resource provider, the treatment would apply to its bids (for generation and load as a bi-directional resource provider) rather than the previous registration categories (as scheduled generation and scheduled load). Refer to the final determination of the rule change for integrating energy storage systems into the NEM: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

Questions for stakeholders

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

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

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

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

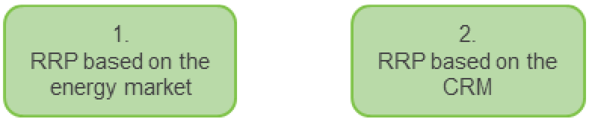
4.2.5 Calculation of RRP

RRP is used for the following calculations:

- settlement of the energy market
- settlement of non-scheduled generation and load
- reference price for contracts
- settlement of interconnectors (discussed in section 4.3.2).

Figure 20 outlines two key options for the calculation of RRP within the CRM design.

Figure 19 Design choices for the calculation of RRP



The two key formulations of RRP are slightly different and appear almost algebraically equivalent when only the energy market is considered. There are impacts for the treatment of FCAS and inter-regional settlement residues (IRSR) which are considered in section 4.3.1 and section 4.3.2 respectively.

The ESB seeks feedback on the design options and will share outcomes with AEMO as part of the proposed detailed design specification for implementation. There may be technical challenges that affect which RRP calculation can be adopted in practice.

Table 13 outlines the two options for the calculation of RRP.

Table 13 Two options for the calculation of RRP

	Option 1	Option 2
Title	RRP is the marginal cost of an additional unit of load at the RRN in the energy market, as it is currently calculated.	RRP is the marginal cost of an additional unit of load at the RRN in the CRM.
RRP	RRP_{NEM}	RRP_{CRM}
Customer payments	= load x RRP_{NEM}	= load x RRP_{CRM}
LMP	CRM adjustments priced at LMP	Same as Option 1.
Access to RRP	Determined by the energy market based on market participant bids	Same as Option 1
Final physical dispatch	Determined by the physical dispatch including CRM adjustments	Same as Option 1.
Generator revenue (constrained)*	= G_{NEM} x RRP_{NEM} + G_{ADJ} x LMP	= G_{NEM} x RRP_{CRM} + G_{ADJ} x LMP
Generator revenue (unconstrained)	= G_{NEM} x RRP_{NEM} + G_{ADJ} x RRP_{CRM}**	= (G_{NEM} + G_{ADJ}) x RRP_{CRM} = G_{CRM} x RRP_{CRM}
FCAS settlement	= FQ_{NEM} x FP_{NEM} + (FQ_{CRM} – FQ_{NEM}) x FP_{CRM}	= FQ_{CRM} x FP_{CRM}
FCAS dispatch and pricing	Two FCAS dispatches including: • FCAS dispatch and pricing based on the energy market (NEM FCAS prices) • FCAS dispatch adjustments and pricing based on the CRM (CRM FCAS prices)	Two FCAS dispatches including: • FCAS dispatch based on the energy market and pricing from the CRM • FCAS dispatch adjustments and pricing based on the CRM

Where:

G_{NEM}	dispatch of a unit from the energy market (MWh)
G_{ADJ}	dispatch adjustments from the CRM = G_{CRM} – G_{NEM} (MWh)
RRP_{NEM}	RRP from the energy market ($/MWh)
RRP_{CRM}	RRP from the CRM dispatch ($/MWh)
LMP	LMP for the unit from the CRM dispatch ($/MWh)
FQ	quantity of FCAS dispatch (MWh)
FP	FCAS price ($/MWh)

** For the purpose of discussion, the formulae ignore settlement based on metered output which is considered separately in section 4.2.6.*

*** For an unconstrained generator, its LMP is equivalent to RRP_{CRM} i.e. the LMP at the RRN from the CRM. The formula highlights there is some basis risk for unconstrained generators in option 1 (settling at RRP_{NEM}) compared to no basis risk in option 2 (settling at RRP_{CRM}).*

Settlement complexity

The use of prices only from the CRM dispatch (Option 2) leads to simpler settlement arrangements for FCAS and for energy from unconstrained generators. The use of prices from the energy market (NEM) (Option 1) means that these outputs are settled at two prices.

Settlement adequacy

The choice of RRP does not itself cause issues for settlement adequacy.

Price differentials between RRP_{NEM} and RRP_{CRM}

There are a few potential reasons why the RRP based on the energy market (Option 1) might differ from the RRP based on the CRM (Option 2) including:

- changes in dispatch for constrained generators in looped flow networks as a result of:
    - changes in bidding behaviour between the energy market and CRM
    - changes in demand from storage acting as load in the CRM (relieving constraints)
- changes in interconnector flows as a result of:
    - differences in bidding behaviour between interconnectors bidding at cost and generators bidding at the market floor price
    - removal of interconnector clamps in the CRM physical dispatch.

Arbitrage activity closing the price differential

If RRP_{NEM} is used for energy settlement (Option 1), an unconstrained generator will sell part of its output at RRP_{NEM} and the remainder at RRP_{CRM} (equivalent to its LMP). The relative quantities will depend upon how it bids into the energy market. Given the choice – and perfect foresight – a generator will prefer to sell at the higher RRP as follows:

- If *expected* RRP_{NEM} > *expected* RRP_{CRM}
    - maximise access allocation in the energy market by bidding at the market floor price to get access to the higher RRP_{NEM}
    - this will tend to reduce the level of RRP_{NEM}.
- If *expected* RRP_{NEM} < *expected* RRP_{CRM}
    - minimise access allocation in the energy market so that it is paid at the higher RRP_{CRM}.
    - this will tend to raise the level of RRP_{NEM}.

In both cases, arbitrage activity would close the price differences, by moving RRP_{NEM} closer to the level of RRP_{CRM}. It should be noted that this closure of the price differential does not resolve the separate arbitrage issues discussed in section 4.2.3.

Option 2 would remove this arbitrage opportunity for unconstrained generators. They would be settled at a single price using RRP_{CRM} and CRM FCAS prices However it could lead to generators that provide FCAS in the energy dispatch not being properly hedged against the RRP when they are backed off from the energy market to provide FCAS. FCAS considerations will be explored further in the technical implementation plan that will incorporate detailed design choices from this Directions Paper (refer to section 4.3.1).

Table 14 Description of design choices for the calculation of RRP

Option	Description	Pros	Cons
1. RRP based on the energy market	RRP is the marginal cost of an additional unit of load at the RRN in the energy market, as it is currently calculated.	It retains consistency with market participants' framing of today's energy market. Price arbitrage between RRP_{NEM} and RRP_{CRM} would theoretically lead to their convergence. It could avoid reopening of long term contracts in many instances.	Payment at RRP_{NEM} does not necessarily reflect the marginal cost of consumption at the RRN. Arbitrage activity may not close the differential between RRP_{NEM} and RRP_{CRM}. There is energy basis risk for unconstrained generators at the RRN = G_{ADJ} x (RRP_{CRM} – RRP_{NEM}).
2. RRP based on the CRM	RRP is the marginal cost of an additional unit of load at the RRN in the CRM. It applies a similar methodology to how FCAS bids are incorporated into the current RRP calculation.	It retains consistency with the concept that the RRP is based on physical dispatch. Payment at RRP_{CRM} reflects the marginal cost at the RRN. Non-scheduled load and generation are settled at the marginal cost at the RRN. It avoids the risk that arbitrage activity does not close the price differential between the two RRPs. RRP_{NEM} could remain distorted by strategic bidding to the market price floor. It avoids basis risk for unconstrained generators at the RRN. It is easier to manage interconnector clamping. Refer to section 4.3.2 below.	Implementation issues will be further assessed as part of the detailed design subsequent to this Directions Paper. It may require the reopening of long term contracts.

Questions for stakeholders

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

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

4.2.6 Settlement of metered output

In today's energy market, participants' metered energy (adjusted for losses) is settled at the RRP. The CRM introduces two different prices into the settlement equation and the single metered energy value must be allocated in some way to the two prices.

Even if the participant achieves their MW dispatch target at the end of the trading interval their metered MWh energy over the interval will be a function of their output trajectory during the interval and any auxiliary load (load used in the plant behind the grid connection point). There are a variety of reasons for failing to hit a dispatch target such as the variability of wind/solar, provision of regulation FCAS services and non-conformance.

A key design decision is the settlement of differences between metered output and dispatch targets at RRP or LMP. The options are detailed below and ignore losses for simplicity. G_{ADJ} represents the CRM adjustments between the target dispatch of the CRM and energy market (G_{ADJ} = G_{CRM} - G_{NEM}). $G_{metered}$ represents the metered output of the plant in the trading interval which includes any dispatch deviations and auxiliary load.

Option 1. Metered output is priced at RRP

Settlement = $G_{metered}$ x RRP + G_{ADJ} x (LMP – RRP)

Under this option, metered output is paid at the RRP (including dispatch deviations) which is consistent with today's settlement approach. The participant is paid LMP less RRP (which is generally a negative number) for its CRM adjustments based on the target dispatch outcomes of the CRM and energy market. Participants that opt out (i.e. G_{ADJ} = 0) continue to have no exposure to LMP. This option treats the incremental CRM dispatch as analogous to the approach used for FCAS settlement i.e. paid on dispatch.

Option 2. Metered output is priced at LMP

Settlement = $G_{metered}$ x LMP + G_{NEM} x (RRP – LMP)

Under this option, metered output is paid at the LMP and the energy dispatch target (in MWh) is paid at RRP less LMP which is generally a positive number. If a participant's metered energy is the same as their energy dispatch target, they will receive the RRP on their output. Generators will have some exposure to LMP where their metered output differs from their dispatch targets.

Figure 21 and Figure 22 illustrate the options for settlement when applied to two different scenarios.

Figure 21 shows a scenario that assumes the participant opts out of the CRM and its metered output is less than the dispatch targets i.e. metered output is less than G_{NEM} and G_{ADJ} = 0.

Figure 20 Design choices for the calculation of settlements – scenario metered output < G_{NEM}

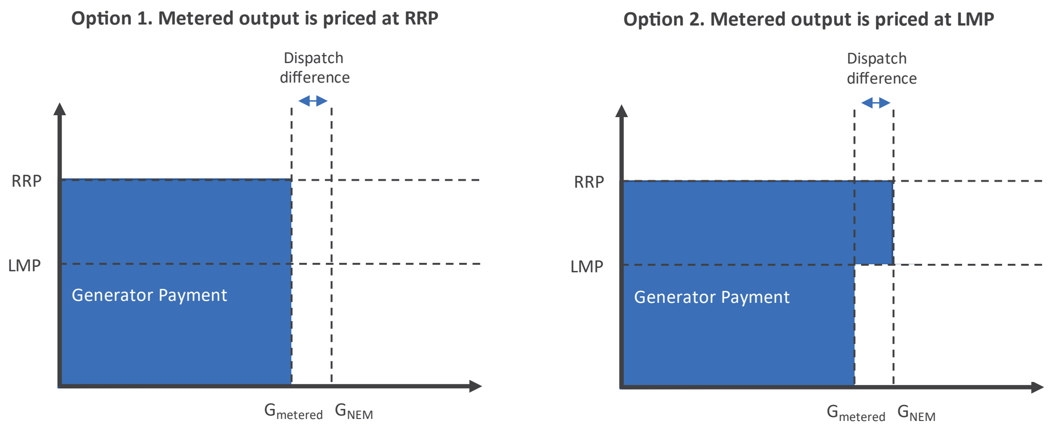


Figure 22 (overleaf) assumes that the participant opts into the CRM and its metered output exceeds the dispatch targets i.e. metered output is greater than G_{CRM}.

Figure 21 Design choices for the calculation of settlements – scenario metered output > G_{CRM}

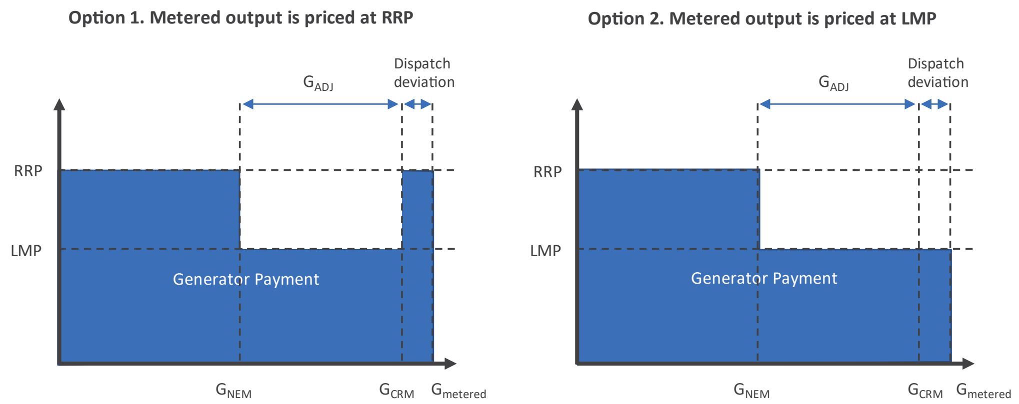


Table 15 Description of design choices for the settlement of metered output

Option	Description	Pros	Cons
1. Metered output is priced at RRP	Metered output is paid at the RRP i.e. including dispatch deviations. The participant is paid LMP less RRP for its CRM adjustments between the target dispatch outcomes of the CRM and energy market.	Participants that opt out continue to have no exposure to LMP. It treats the incremental CRM dispatch as analogous to the approach used for FCAS settlement i.e. paid on dispatch.	As with the current market, it creates incentives to not follow dispatch instructions when the RRP is high. This risk is currently mitigated by AEMO's non-conformance monitoring.
2. Metered output is priced at LMP	Metered output is paid at the LMP. The participant is paid RRP less LMP for its energy market dispatch.	It removes incentives for generators to deviate from their target dispatch. It aligns the generator's incentives with AEMO's objective for system security. Participants receive LMP at the margin so are incentivised to bid and operate according to their actual costs which should improve efficiency.	All participants are likely to have some exposure to LMP relating to their dispatch deviations, even if they opted out of the CRM. Formulation of payments in this way could impact financial contracts. This risk may be low given the materiality of dispatch deviations and given that generators have existing processes and systems to manage them.

Questions for stakeholders

The ESB has outlined two options for the formula of settlements.

Q7. Do you agree with the risks and benefits of the two options and their materiality?
Q8. Do you have a preferred settlement formula and why?

4.3 Issues under consideration

The Directions Paper introduces a number of key design choices. The ESB will review stakeholder feedback to inform the detailed design of its recommended model. This section flags additional issues that will be considered during the detailed design stage.

The nature and residual materiality of the issues are partly dependent on the design choices. We are not seeking direct feedback on these issues at this time but we have provided preliminary discussion for reference.

The CRM design allows for participants to opt in or out of the CRM. This is a key design principle guiding the implementation plan, in addition to those defined by the transmission access reform objectives.

4.3.1 Implementation issues for FCAS

Energy and FCAS bids must be co-optimised in the same dispatch to achieve an optimal cost solution. There are some general options to consider as part of this co-optimisation in the CRM design:

- whether FCAS should be dispatched in the energy market as well as the CRM
- how FCAS should be settled i.e. at NEM FCAS prices, CRM FCAS prices or a combination
- how FCAS settlement interacts with the energy settlement.

The net outcome of the energy market and CRM is to achieve a security constrained dispatch that can satisfy the energy and FCAS requirements, as it does today. The benefit of the CRM design is that it provides an efficient mechanism to redispatch resources in the energy market to more efficient levels. This is likely to result in changes to both energy and FCAS targets.

The ESB is working with AEMO to develop the specification of the CRM design and allow AEMO to progress its assessment of the implementation risks and to develop a viable technical plan.

4.3.2 Treatment of interconnectors

The detailed plan of the CRM design will need to consider how the formula for inter-regional settlement residue (IRSR) applies to:

- regulated HVDC interconnectors
- regulated AC interconnectors
- market network service provider (MNSP) HVDC interconnectors.

Regulated interconnectors

In the current market design, the IRSR for a regulated interconnector is calculated as the difference in the RRP between two regions multiplied by the power flows between those regions.[32] The current formula for IRSR could continue to apply but there may be options to modify it to take into account changed power flows in the CRM.

The current AC interconnectors are notional (virtual) interconnectors which actually comprise a network of AC lines. If the IRSR calculation is modified to take into account the changed power flows and LMPs in the CRM, there could be technical challenges in determining the changed physical line flows from the energy market dispatch to the CRM dispatch if the interconnector is composed of multiple physical AC lines. This is not an issue for interconnectors solely composed of one or more HVDC lines.

MNSP

The settlement for a MNSP is based in its physical connection points like a generator or load and hence is based on metered energy and includes loss factors.[33] The current formula for MNSP settlement could continue to apply but there may be options to modify it along the lines for CRM payments for batteries.

32 There would also need to be an adjustment for losses.

33 Refer to definition of TLF in the NER Clause 3.15.6 https://energy-rules.aemc.gov.au/ner/175/24068

The calculation of the IRSR settlement does not have any implications for the clamping approach. As described below, the interconnectors would be clamped as per status quo in the energy market, but not in the CRM.[34]

Clamping dispatch in the energy market

Generally, interconnector flow direction is from the lower price to the higher price region, ensuring a positive settlement payment. However, it is possible for the interconnector to flow in the opposite direction, called a counterprice flow, leading to a negative IRSR i.e. settlement deficit where *IRSR < 0*.

The NER specifies that the TNSP in the importing region must make a corresponding payment into AEMO settlement to offset this settlement deficit.[35] In accordance with its current system operating procedure, AEMO clamps interconnectors during periods of counterprice flow to prevent the negative residues from growing too large and materially affecting TNSPs and, ultimately, customers.[36]

It is likely that an interconnector clamp will need to apply in the energy market in the same way as today's rules. Clamping would affect dispatch outcomes for generators in the energy market and IRSRs but it would be consistent with today's approach to dispatch and pricing in the NEM (other things being equal). AEMO will review its clamping procedures as part of the implementation plan.

No clamping requirements anticipated for the CRM

There is potential that clamping of interconnector flows is not required in the CRM. As a general principle, participants would have no incentives to create counter price flows when they are paid at the LMP.

Because the CRM uses LMP prices for CRM adjustments, generators are more likely to bid around their marginal costs rather bid at the market floor price to get access to the RRP in the energy market. The power flows over an inter-regional boundary will generally be from lower priced nodes to higher priced ones and there will be no deficit with LMP settlement. The CRM may create opportunities for improvements in dispatch efficiency related to interconnector flows.

Settlements residue auction

There are no proposed changes to the structure and design of the settlements residue auction (SRA). AEMO will separately review and consult on the introduction and impact of PEC creating looped regions.

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34 The ESB notes that AEMO will separately consult on the impact of Project EnergyConnect (PEC) which will create a network loop between the regional nodes of SA, VIC and NSW. A network loop between regions has not previously existed in the dispatch network topology. The form of the clamping constraint will be developed by AEMO as part of its assessment of Project PEC.

35 Clause 3.6.5(a)(4) of the NER https://energy-rules.aemc.gov.au/ner/388/111163#3.6.5

36 AEMO, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2019/5ms-dispatch-non-rules-procedures/automation-of-negative-residue-management---clean.pdf?la=en&hash=AF18F4DEB855C10F9A1374C424FC4359#:~:text=AEMO%20uses%20automated%20constraints%20to,as%20of%201%20July%202010)

4.3.3 Market participants that alleviate constraints

The design choices have focused on generators that contribute to constraints (where *LMP<RRP*). However, there will be pockets of the network where LMP is higher than RRP. This is particularly true for inter-regional prices and outcomes of the spring washer effect.[37] Prices upstream of the constraint will be lower than RRP (*LMP<RRP*) and prices downstream of the constraint will be higher than RRP (*LMP>RRP*).

In today's energy market, generators that alleviate constraints may be 'constrained on'. AEMO refers to this as a negative mis-pricing event whereby a generator is dispatched despite RRP being less than its bid price.[38] It is not considered to be a material issue in today's dispatch outcomes.[39]

In theory, generators that *alleviate* a constraint should be rewarded by receiving a price higher than the RRP. Their LMP will likely be higher than the RRP in the CRM. This incentivises the generator to alleviate the constraint, increasing dispatch efficiency.

However, a number of problems could arise by allowing the LMP to be greater than the RRP, which the ESB is continuing to analyse:

- generators that alleviate constraints with an LMP greater than the RRP could have considerable market power
- settlement deficits may arise given non-scheduled load pays the RRP
- wealth transfers may arise for market participants that alleviate constraints compared to the status quo arrangements (given that they are currently only settled at the RRP).

Allowing LMP to be greater than the RRP does not directly lead to a settlement deficit but could indirectly lead to it as a result of the bidding incentives. If participants withhold from the energy market and participate in the CRM, it could result in load shedding in the energy market which is then fulfilled by the CRM dispatch. Unscheduled load will pay at the RRP and the CRM participant could receive the higher LMP.

A simple solution to these problems is to cap the LMP at the RRP, although this would negate the locational signals for new congestion relief providers and dispatch efficiency benefits. The cap could be applied to different participant types depending on the objective e.g. all generators, only to legacy generators, or only to in-merit legacy generators. Directed on market participants would continue to be remunerated in accordance with current NER framework for intervention pricing and compensation.[40]

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37 Refer to figure C.5 p. 128 for an explanation of the spring washer effect AEMC, https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF, June 2019

38 See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/guide-to-mis-pricing-information.pdf?la=en

39 AEMO reviewed its quarterly mis-pricing reporting as part of the Congestion Information Resource consultation. The number of requests to review the report was at a low level. AEMO discontinued its publication since July 2015 which gives some indication as to the relative materiality of the issue: https://aemo.com.au/en/consultations/current-and-closed-consultations/2015-congestion-information-resource-guidelines-consultation

40 See https://www.aemc.gov.au/rule-changes/intervention-compensation-and-settlement-processes

Alternatively, these market participants could be paid at the LMP and the difference between the LMP and RRP be treated as a network ancillary service and its costs be recouped e.g. via the TNSPs or an uplift to RRP. This would preserve the dispatch efficiencies of the CRM, provide incentives to locate in areas of higher LMPs and fund any energy settlement shortfalls. Market power considerations could be treated through a specific market power mitigation mechanism.

The detailed design choices in this paper will help to clarify the residual issues and solutions where LMP is higher than RRP. The ESB will reassess and propose solutions as part of the detailed designs to be released after this Directions Paper.

4.3.4 Arbitrage opportunities for scheduled load

There are currently few scheduled loads operating in the NEM apart from storage. Hence the design choices have focused on storage acting as a generator and as load.

Similar to storage, scheduled load can play a key role in the future energy system to relieve congestion. There will be more incentives for load to register as scheduled with the introduction of LMPs which may be attractive to future hydrogen electrolyser projects to charge at a lower cost.

However, scheduled load has a similar opportunity to gain profits from strategic bidding in the energy market and CRM, without improving the efficiency of the final dispatch. Refer to Table 16 for a comparison of the bidding incentives.

Table 16 Arbitrage bidding in the energy market – scheduled load

Coefficient	Merit position	Bidding incentives $/MWh		
		Today's energy market	Future energy market	Future CRM
Negative – relieving congestion	*In-merit*	+$15,500	+$15,500	at cost
	Out of merit	at cost	+$15,500	at cost

The design choices in this paper will help to clarify the residual issues and solutions for scheduled load. In particular, this refers to the design choices outlined in section 4.2.4 for storage as load, and the consideration of market participants that alleviate constraints in section 4.3.2. The ESB will reassess and propose solutions as part of the detailed designs to be released after this Directions Paper.

5 Detailed design choices - investment timeframes – locational signals

5.1 Overview of chapter

This chapter outlines key design choices relating to the investment timeframes, with the exception of the proposal for enhanced investor information, which is considered separately in Chapter 6. A foundational question is the nature of the signal used to encourage investors to make efficient location decisions. Table 17 outlines the two key variants of the hybrid model which allocates access to the RRP based on quantity (priority access) or a price signal (congestion fee).

Table 17 Overview of options for the nature of the locational signal

	Priority access	Congestion fee
Basis	This variant integrates enhanced information, the transmission queue model (TQM)[41] and the CRM.	This model variant integrates enhanced information, congestion fees and the CRM.
Description	This variant establishes a queue to determine which generators receive priority access to the RRP in the energy market during periods of congestion when bids are equal at the market price floor. If a more efficient dispatch outcome can be achieved, the CRM facilitates these trades. Provides more investment certainty around future curtailment levels, which helps to reduce the cost of capital required to invest in the NEM.	This variant leverages the transmission planning process to administer fees that reflect the level of available hosting capacity for new generation. The purpose of this process is 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.

The key advantage of the priority access variant is that it corrects the features of the NEM that make it riskier for investors than other comparable markets. However, measures to reduce curtailment risk for investments being made today may have the effect of increasing the level of curtailment faced by future investors. Hence it will be necessary to carefully calibrate the hybrid model in a way that balances the need to reduce congestion risk against the need to support investment across all stages of the energy transition.

41 The original TQM proposal is described in Appendix F.

5.2 Key design choices

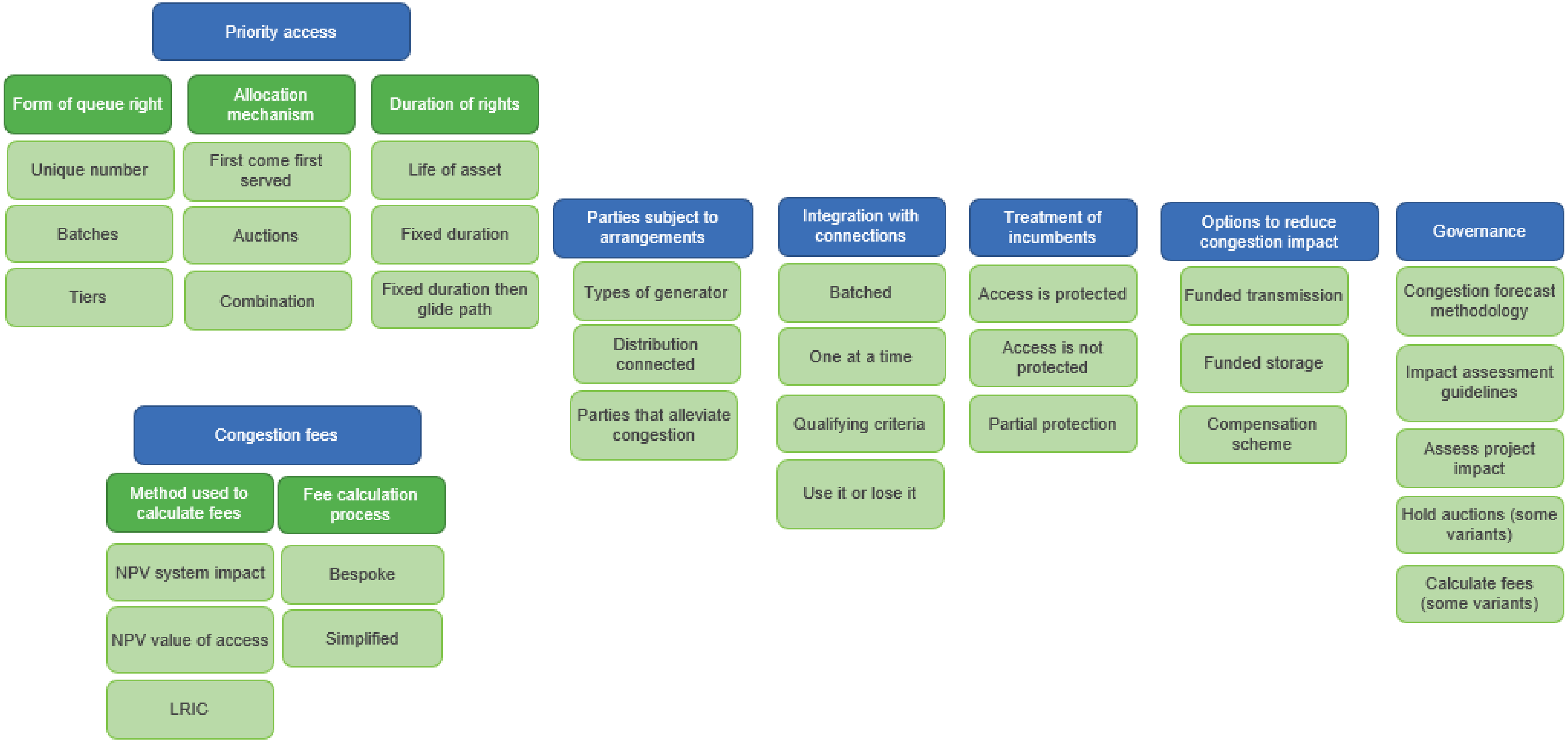
Table 18 summarises the design issues considered under each section of this chapter.

Table 18 Key design choices for the investment timeframes

Section	Description	Overview of design considerations
Priority access (variant)		
5.3	To determine the nature of the priority access rights for eligible generators	Issues for feedback relate to: • the form of the queue right (including the number of queue positions) • how queue rights are allocated in respect of a given MW capacity • the duration of the queue rights.
Congestion fee (variant)		
5.4	To determine how congestion fees will be calculated and the process for assessing the impact of a project on congestion	The metric for calculating congestion fees will affect how widespread the fees are, and the quantum of the fee. The trade-off between providing an accurate locational signal, and the complexity of the fee calculations.
Both variants		
5.5	Which parties would be subject to the access models	Whether the same parties able to participate in CRM should be eligible for priority access (i.e. a queue position) or a congestion fee, depending on the model adopted.
5.6	Integration of setting priority access or finalising the congestion fee with the connections regime	The negotiation of a connection agreement for a proposed new project is a major undertaking. The timing of the setting of the queue priority or the congestion fee and how it is determined need to be integrated with this process. These determinations should not add unnecessarily delays and/or complexity to the connections process.
5.7	To determine how incumbents are treated under transitional arrangements	Under both models, there are questions relating to the appropriate extent of protections for incumbents' existing access and how long they should remain in place (i.e. grandfathering).
5.8	To consider the arrangements for connection applicants to fund network augmentations	Connection applicants may value options that give them flexibility to reduce their exposure to a congestion fee (or unfavourable queue position). For instance, there may be opportunities for a connection applicant to fund an incremental investment in the shared transmission network in return for a lower fee, or improved queue position.
5.9	To determine the governance arrangements for the investment timeframe models	Depending on which variant is adopted, a framework is required to govern the conduct of auctions for priority queue positions, and/or calculate congestion fees.

Each section of this chapter introduces a summary table that lists the design choices for each issue and questions for stakeholder feedback. Figure 23(next page) provides an overview of the design choices in investment timeframes.

Figure 22 Overview of design choices in investment timeframes



5.3 Priority access

This variant of the hybrid model establishes a queue to determine which generators receive access in the energy market. Each generator is assigned a queue number (which might be unique or shared with other generators), the higher the queue number, the lower the dispatch priority. Queue priority only becomes relevant where generators have tied offer prices typically when both are bidding at the market price floor to minimise curtailment.

To the extent that a high-cost generator is preferred over a low-cost generator due to its superior queue position, this prioritised dispatch has the potential to be inefficient. However, we expect efficiency to be restored in the CRM dispatch, as described in chapter 4. Further considerations that need to be weighed are:

- the potential for market participants to opt out of the CRM,
- the benefits to investors and consumers arising from investors facing less risk, and hence being able to access a reduced cost of capital, and
- the extent to which curtailed generators share the same marginal costs.

When congestion occurs, generators at the front of the queue would be preferentially dispatched in the energy market. Those towards the back of the queue who are not dispatched, or not dispatched fully, in the initial dispatch run can bid into the CRM to purchase congestion relief from generators with access to be physically dispatched. The ESB is seeking stakeholder feedback, both on this model and key design questions within the model, as follows:

Section	Description	Design choice
5.3.1	To determine the form of queue right	How many queue positions there are, and whether future generators share queue positions, will impact the nature of priority access for eligible participants. The options are: • newly connecting generators join the back of the queue, and receive a unique queue number, • generators seeking connection are grouped into tranches with the same queue number • group participants into a small number of tranches that confer high/medium/low priority access • newly connecting generators join the back of the queue and receive a unique queue number. Outcomes are periodically reviewed and the unique queue numbers are consolidated into a pre-determined small number of queue positions which deliver very similar outcomes.
5.3.2	The process by which market participants are assigned a queue position	Proposed options are: • First come first served • Via auction • Combination of both
5.3.4	How queue numbers are grouped or adjusted during a market participants' operating life	The rights could be made available for the life of the asset, or some shorter fixed period. If the rights have a fixed duration, there is a question as to whether they should cut out all at once or decline gradually over time. There may also be situations where it is appropriate to amend a market participant's queue position.

Section 5.3.4 outlines alternative approaches by which participants might change their queue position.

5.3.1 Form of queue right

The key benefit of the priority access variant is that existing generators cannot have their access eroded by generators with a subordinate queue position. Consequently, investors can manage their access risk. This meets the objective of addressing elements of the current market design that amplify investor risk above what would occur in a natural competitive market.

New generators connecting in congested areas will face the cost of the congestion they cause – but this is by design. The queue disincentivises but does not prohibit generators from connecting in congested areas and provides assurance that regardless of where they connect their access will not be eroded by another, subsequent connecting generator. The alternative - exposing existing generators to the risk of new congestion caused by new entrants - may seem to be of benefit to those new entrants. However, the benefits to the new entrants would be transient; once a new entrant becomes an existing generator, its access can then be eroded by another subsequent connecting generator, and so on. The queue makes the cost of congestion to new entrants more predictable, even if the level of congestion is higher than under the status quo where it is shared with incumbents. Greater certainty may have the overall effect of reducing the cost of capital, other factors held equal.

Correcting the features of the NEM that make it unduly risky for investors is a key objective of access reform. However, it is not the sole objective – the arrangements also need to have regard to other assessment criteria which, in some cases, have a countervailing influence. In particular, any changes should promote an effectively competitive wholesale market by avoiding creating barriers to efficient new entry.

Measures to reduce curtailment risk for today's investors may have the effect of increasing the level of curtailment faced by future investors, depending on the duration of rights awarded and the level of curtailment built into the rights of priority access holders. This trade-off is especially critical given that the energy market is in a period of transition – and in the future, the efficient level of congestion will be substantially higher than at present (see section 2.1.1).

The model design should therefore carefully consider how it balances the interests of new entrants versus incumbents over time. Relevant design choices include the role of grandfathering, whether rights should be auctioned, the duration of the rights, and whether the level of congestion faced by priority queue rights holders should be designed to increase over time in line with the efficient level of congestion in the system.

In this context, key design questions include the number of queue positions (and hence the extent to which the cost of congestion are shared among generators with the same position in the queue), the level of curtailment associated with each queue position, and whether the level of curtailment associated with a given queue position can change over time.

Unique number for newly connecting generators

The 'purest' application of a queue model would be for newly connecting generators to be allocated the next available queue number at some pre-determined event in the connection process.

Under this option, there would be a single NEM-wide queue allocated on a broadly first-come first-served basis.[42]

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42 Except in the special case of REZs, and taking into account any arrangements for managing multiple simultaneous connections

This approach reflects the concept that the queue only tie-breaks generators that are participating in the same binding constraints. If an area becomes more congested because of the subsequent connection of another generator in the area, the original generator will have a lower queue number than the subsequent connecting generator. This will give the original generator priority access relative to the new generator, even if it has a notionally “high” number in the national queue. In other words, it is the *relative* queue positions of generators in binding constraints that matter.

This option provides the most certainty to investors. An investor would be able to conduct their congestion modelling based on known projects and forecast network upgrades and have confidence that even if another project connects nearby, it will not undermine their access. A further advantage is that it avoids the need for a centrally administered process to decide where, and for how much capacity, queue positions are available (except in the special case of REZs). Instead, market participants can take a view based on their own assessment of the commercial prospects of their investment proposition.

In practice, unique queue numbers may present challenges for the dispatch engine to solve in the time necessary to then undertake any CRM trade and hence determine physical dispatch every five minutes. This model in its purest form may be limited by implementation considerations. However, given that there is a spectrum of potential solutions, the ESB seeks stakeholder views on extent to which we should work towards providing a ‘pure’ signal with respect to congestion, and removing cannibalisation as much as possible.

A pure model has the potential to be relatively inflexible when it comes to managing the increase in overall system congestion over time. As there is no sharing within queue positions, the balance between the interests of new entrants and incumbents would need to be achieved by other means (such as the duration of queue rights). On the other hand, softening the regime to make it easier for new generators to connect to the grid involves a trade-off as it comes at the expense of existing generators.

A further consideration with an approach that adopts an absolute priority sequence is that there may be situations that there is not enough access allocated to meet demand due to the low queue number generators with high constraint coefficients effectively constraining the dispatch of generators with small coefficients in binding constraints. Queue rights would need to be adjusted to the extent required to achieve a feasible, secure dispatch solution.

It would be necessary to establish a clear framework for managing the queue, including the process used to allocate queue positions and the interaction with the connections process. These issues are discussed further in section 5.3.2 and 5.6.

Batches

It may be possible to consolidate the number of queue positions using batching. For example, all generators reaching the relevant stage of the connection process within a twelve month time window may all be allocated the same queue position.

This would reduce the number of queue positions. Further, any limit on the duration of access rights would create a finite limit on the number of queue positions. For instance, if queue positions last 10 years, and all generators that connect within a given year are in the same batch, then there would only be 10 queue positions. Nevertheless, there may still be implementation challenges.

Relative to the unique queue position option, a generator would be slightly less confident that any subsequent generators do not affect its access. Another generator may connect afterwards but within the same time window, securing the same queue position. Access would then be allocated between these generators on the basis of constraint coefficients if both bid at the floor price in the initial energy dispatch.

If appropriate, the batches could be designed to align with the batching framework under consideration as part of the AEMO/Clean Energy Council Connections Reform Initiative.[43]

Tiered access – predetermined small number of queue positions

This variant proposes a small number of predetermined queue positions (e.g. two or three, say). These would correspond to different classes of "firmness" of access rights. For instance, generators could have primary, secondary or tertiary level access.

Where there is little spare capacity, generators would be required to join the last position (e.g. tertiary access). Where there is, or is shortly expected to be, spare capacity (for example because of transmission expansion or generator exit), new MW of queue positions would be available further towards the front of the queue. Generators would be able to purchase these queue positions, perhaps through an auction (discussed below).

The quantity of MW of queue positions would be carefully determined through load flow modelling. Allocating too many MW of queue positions would reduce the access of generators that have already invested, diminishing their ability to manage risk. This would not just affect incumbent generators at the time the market reforms are introduced, but also any yet-to-invest generators from the time of the reforms, in turn increasing their cost of capital. Conversely, allocating too few MW of queue positions would mean that too many generators are going to the back of the queue and diminishing their ability to manage access risk. Furthermore, the process of determining the quantities of MW could itself be complex and controversial.

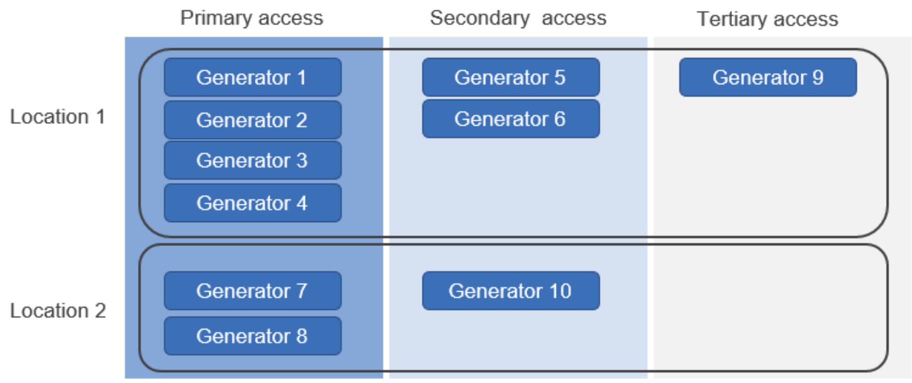
Unique queue numbers with periodic reviews to classify into tiers

Generators with a notionally high queue position (i.e. towards the back) may nevertheless enjoy good financial access if the generators ahead of them in the queue do not participate in the same constraints, or do so but collectively do not (or only rarely) "exhaust" that constraint and make it bind.

One option could be to periodically (say, annually) assess the unique queue numbers and temporarily group generators together into access tiers. The tiers would be used that year in the allocation of access. There would be scope for a generator to move between access tiers as network conditions and binding constraints evolve over time. The relative queue positions of market participants contributing to the same binding constraints are fixed, even as the tiers that a queue number is allocated to varies. Over time, a generator would expect to move up the tiers as older generators retire. Figure 24 provides an example.

43 See https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/connections-reform-initiative

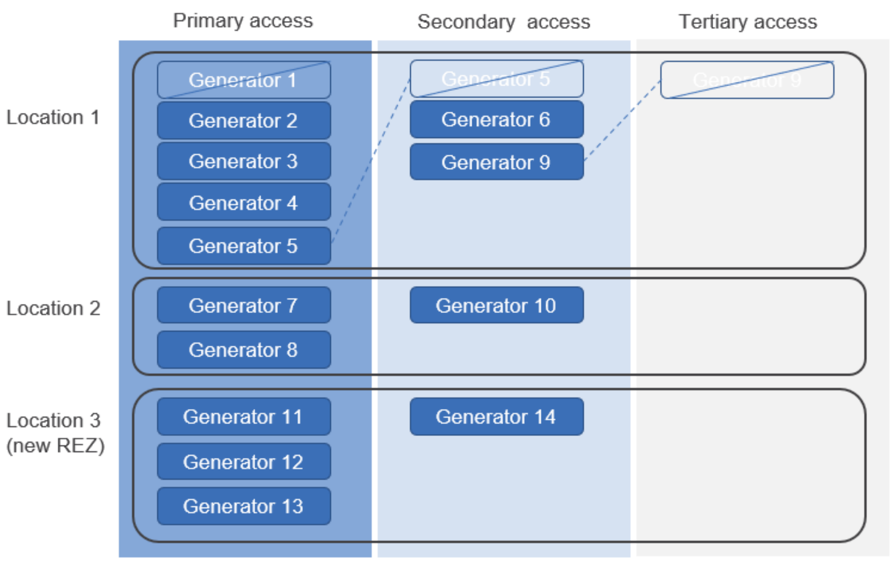
Figure 23 Access tiers with periodic reviews



For example, assume there are 10 generators who are each allocated a unique queue number based on the order in which they connect. Generators with positions 1 through 4 might enjoy good access owing to their good queue positions, while generators 7-8 enjoy good access owing to their location in an unconstrained part of the grid. These may be grouped together into the lowest queue position (i.e. the primary access tier). Generators 5, 6 may compete in the same binding constraint as the first group of generators and so they are allocated secondary access. Later connecting generators are classified according to the level of available hosting capacity in their part of the network.

Subsequently, Generator 1 retires and new transmission is built to connect a new REZ to the system (Figure 25).

Figure 24 Access tiers classifications are updated as power system evolves



The periodic review establishes that Generator 5 and Generator 9 each get to move up a queue position in light of the hosting capacity freed up by Generator 1's retirement. Generators 11-13 successfully compete in the REZ tender process and hence receive primary access. Generator 14 is outbid in the REZ tender process. They may still connect within the REZ, but they must accept secondary access.

This option is designed to be more practical to implement while also retaining the advantages associated having a unique queue number. It also provides a framework that enables the level of congestion faced by priority queue rights holders to increase over time in line with the efficient level of congestion in the system. The downside is that the periodic reviews and classification into tiers has the potential to reduce the level of investment certainty. It would be necessary to establish a clear methodology for the periodic review process.

Summary of options

Unique queue numbers provide the most clarity for investors but may be challenging to implement. Alternative approaches that reduce the number of queue positions may reduce these implementation challenges, but partially compromise the ability of generators to manage congestion risk.

Question for stakeholders

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

5.3.2 Allocation mechanisms

There are various queue allocation methods that could be applied. Some options are discussed below.

First come first served

Under this option, generators would simply join the back of the queue at the time of some pre-determined event in the connection process. No fee would be paid to do so.

There would be no pre-determined, regulatory limit on the number of generators (or MWs) that could receive a place in the queue. This is because they are joining at the back, so they cannot harm the access of existing generators (although they can harm the access of generators with the *same* queue number, if any of the non-unique queue number options described above are used).

A generator that connects in a currently uncongested area will enjoy good access despite being at the back of the queue, safe in the knowledge that subsequent connections cannot erode its access. Conversely, a generator is free to join the back of the queue in a highly congested area but is unlikely to enjoy much financial access (and will instead have to participate in the CRM to get dispatched).

The main advantage of this approach is its simplicity. As discussed in section 5.4, determining a fee is likely to be challenging, as would determining the quantity of generator MWs that could reasonably be accommodated in different parts of the network. All of this is avoided by allowing generators to join the back of the queue for free.

At a given time, the back of the queue may have significant value in parts of the grid that only become significantly congested when later subsequent connections join (even further back in the queue). This may prompt:

- a rush of connections to secure a valuable queue position, or
- investment in inefficient locations which use up lots of the access rights (due to a high coefficient), leaving little financial access available for other market participants.

These issues may not be particularly material, because in practice many locations on the grid may already be reasonably “full”, and so the value of a queue position at the back is modest. The incentive to locate primarily on the basis of an access allocation over other relevant factors such as resource availability would also be modest.

Auctions

An alternative option is to hold an auction. Based on load flow modelling, the auctioneer (which could be a jurisdiction developing a REZ) could *reserve* MWs of capacity for different generator types at queue positions. This reserved capacity could be:

- at the front of the queue, particularly if there are only a small number of predetermined queue positions, as described above. The access of existing generators would not be eroded providing the additional transmission capacity exceeded the likely access being granted to new generators joining the front of the queue
- at the back of the queue, particularly under the approaches where there are more, or even many unique, queue positions.

The second approach may seem counterintuitive, but the back of the queue could still be extremely valuable to REZ-connecting generators. The transmission expansion may allow generators even at the back of the queue to enjoy good or even unlimited access, and it enables them to manage the congestion risk arising from generators connecting outside of the REZ process "poaching access". By reserving capacity in bulk for the auction (e.g. for the REZ), any generators choosing to connect outside of the auction/REZ process would be required to join the *very* back of the queue, behind the reserved capacity. A queue position number of 20 that is associated with new transmission capacity will still provide firm access if all generators that are competing for access to the same transmission assets have a queue number that is greater than 20.

The auction would need to be carefully designed. The same queue position could have two different values for two different generators, depending on their availability profiles and locations. This could distort investment decisions, if, for example, a pay as clear approach is used. As a result, it might be necessary to constrain participants in the auction to generators with similar coefficients and technology type – i.e. geographically constrain the auction to a REZ, and run separate auctions for wind and solar. The size of the zone would be critical: too small and running a competitive auction is difficult; too large and this doesn't constrain the inefficient investment decisions.

Furthermore, a central agency would need to carefully consider how much generation, and what type, would be reserved (and at what position in the queue). Allocating too many new queue positions near the front would be good for the new investors but would disrupt the access of incumbents, including those that invested since the introduction of the reforms on the expectation that the value of their queue position would not diminish. This in turn could increase the cost of capital for all. Even over-reserving MWs at the back could be problematic as generators may place little value on having to share access with lots of other generators who have the same queue position.

The auction would reveal the value of a queue position for prospective generators. Revenue from the auction could be used to offset the cost of new transmission capacity (i.e. offset transmission use of system (TUOS) charges paid by consumers). A mechanism for integrating auctions into the connections process is discussed in section 5.6.3.

Jurisdictional REZs could be integrated into the access priority model (and vice versa). Jurisdictions could reserve MW of generation in the queue while they develop a REZ. REZ participants would be granted this favourable queue position as part of the REZ scheme, safe in the knowledge that their access will not be eroded by another generator elsewhere or later.

There would be no need for physical caps on connections, inside or outside of REZs. New generators would be free to connect in the REZ and not participate in the auction, or to connect elsewhere, but would automatically be placed at the back of the queue (including behind the reserved queue positions).

Combination
Alternatively, a combination of the two approaches outlined above (first come first served and auctions) could be used at different locations and at different times.

In parts of the grid that are already significantly congested, first come first served could be most appropriate. The incentives for inefficient investment are likely to be modest, few generators would be expected to compete in an auction anyway, and the fee arising from the auction would be expected to be small. First come first served may be a pragmatic and simple solution in these circumstances.

In contrast, in parts of the grid that are currently uncongested, or opening up as a result of a transmission investment or generator exit (e.g. REZs), the converse is likely to be the case. There could be more significant inefficiencies from generators investing via the first come first served model, more prospect of REZ generators' access being "poached" by fast-moving generators operating outside of the REZ process. In these circumstances an auction (or other administered process) has merit because there would be more generators competing and more revenue recovered to offset transmission expenditure costs.

Summary of options
The first come first served approach is simple and appears to have few downsides when the priority access model is in place and there is little current or prospective spare capacity on the network. In these circumstances, the price signals sent under the first come first served approach approximate the ideal price signals for efficient investment.

The auction approach has advantages when there is or is expected to be spare transmission capacity, and hence the possibility of significant generation investment. REZs are an obvious example of this.

The two approaches could be implemented side-by-side at different times and locations on the network.

Questions for stakeholders

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

5.3.3 Duration of rights

The rights (i.e. a position in the queue) could be made available for the life of the asset, or some shorter period. If the rights have a fixed duration, there is a question as to whether holders of expired queue positions would be moved directly to the back of the queue or if their position would decline gradually over time.

This section discusses the duration of the rights allocated to newly connecting generators after the reform has been implemented. The treatment of incumbent generators at the time of the reforms is discussed in section 5.7. A key consideration for the appropriate length of the rights is the impact on the cost of capital for new investments.

A long-lived and predictable queue position will reduce the cost of capital for new investments. However, over time as the network becomes congested, this will mean yet further new investments are unable to acquire significant levels of access to the RRP unless new transmission is built. On the other hand, if there is no new transmission – for instance due to social licence issues - then the only source of access to new entrants is by cannibalising access of existing generators. We welcome views on the appropriate balance here.

Life of asset

One option is to simply set the access term to the life of the market participant's asset. This would seem to maximise the ability of new entrants to manage congestion risk, although clearly any subsequent connecting generator may not gain favourable access for a considerable time. Under this approach, generators would forfeit their queue position when they exit the market.

If generators are receiving considerable value from a low queue number (i.e. near the front of the queue), this may, all else equal, delay otherwise efficient *dis*investment. In practice, many generators that are expected to retire in the near future may be in relatively uncongested parts of the network, and so the value of a position at the front of the queue is low, and the distortions to efficient behaviour only modest.

Fixed duration

Alternatively, rights could expire at the earlier of generator retirement or a fixed date, with generators going to the back of the queue at that point.

Assuming the fixed date would generally be earlier than the efficient retirement date, this would avoid the possible inefficiencies arising from linking priority access to a generator's exit decision.

Typical PPAs are 5-10 years in length, which might suggest rights of a similar term may be appropriate. These PPAs appear sufficient to underwrite investment, suggesting that longer rights might only have a modest effect in decreasing the cost of capital.

Nevertheless, the level of investment certainty conferred by the priority access model is eroded by moving generators to the back of the queue at a set time. Even if the mechanism was clearly defined upfront, the financial effect would be hard to predict given the complex interactions which determine the value of queue positions at any given time.

Fixed duration with glide path

Queue positions could instead increase over time (i.e. generators would move back in the queue) following a predictable glidepath. For example, a queue position could be fixed for the first 10 years, and then the proportion of a generator's capacity that receives the benefit of the priority queue position could gradually decline over time, with the non-reserved priority being sent to the back of the queue. The mechanism by which the glide path is given effect would vary depending on which option is adopted with respect to the form of the queue right.

This would remove the sudden change in queue position but could nevertheless increase congestion risk overall by allowing subsequent connections to erode a generator's access to the RRP.

Questions for stakeholders

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

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

5.3.4 Changing queue positions

The ESB seeks views on what happens to queue numbers in the event of generator replacements, modifications and expansions. We also discuss the extent to which queue positions may be traded.

Generator replacements, modifications and expansions

If the ESB were to adopt the design choice that an asset's queue right expires on retirement, then this would imply that a replacement asset at the site does not inherit the queue right. Also, the replacement asset would not necessarily have the same congestion impact as the original generator.

This framework should distinguish between generator replacements and refurbishments e.g. replacement of turbine blades on existing towers or foundations.

In the case of generator expansions, one approach could be that generators that expand their capacity would have the additional capacity treated differently to their existing capacity. The additional capacity could be placed at the back of the queue: it would otherwise be "queue jumping" and diminish access of generators further back.

Trading queue positions

Queue positions could not easily be traded between projects given their bespoke characteristics. The value of a queue position is a function of the position and output profile of a given market participant relative to all the other parties in the queue. As a result, trading of queue positions would affect the value of the queue positions held by other market participants.

For example, a generator with a higher coefficient towards the back of the queue and a generator with a lower coefficient near the front of the queue could likely agree on a price to trade positions. This is because the generator towards the back could sell more congestion relief than the generator in front, were their places swapped. While this is desirable for the generators in question, all the other generators behind the generator originally further forwards in queue would have their access diminished.

In operational timeframes, the CRM provides an opportunity for market participants to profitably change their dispatches by trading in the CRM in real time.

Generators would, of course, be free to create financial instruments relating to the cashflow created by being at a particular queue position, and trade these bilaterally, because doing so would not directly affect any other generator.

Options for connecting participants to secure a lower queue number by optimising their project and its impact on congestion are further explored in section 5.8.

5.4 Congestion fees

The objective of the congestion fee variant is to leverage the planning framework to provide locational signals to investors. A connecting generator may be required to pay a one-off congestion fee which is calculated as part of the connection process (but may be recovered over time). The fee would be calculated by a central body, based on transmission and generation planning studies (e.g. the ISP as supplemented by public policy).

The fee would be location dependent, reflecting the level of current and expected future congestion in that location. 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.

Unlike the priority access model, generators in this model have equal rights to be dispatched and receive RRP, similar to the current market design. The CRM would then allow for efficient redispatch.

To assist intending participants, any connection fee regime should be based on a clear, transparent process which allows them to identify prospective projects early in the development process. The process would determine a fixed fee ahead of final project approval which needs to be:

- Repeatable and able to be predicted by participants or their advisers
- Consistent with other post 2025 design measures
- Provide for jurisdictional polices, especially those in regard to REZs.

Ideally, the congestion fee should reflect the size, technology, design and expected operating regime of the new project, to the extent that these factors affect congestion – since this will encourage project developers to have regard to their impact on the broader grid as they design their projects.

The ESB is seeking stakeholder feedback, both on this model and key design questions within the model, as follows:

Section	Description	Design choice
5.4.1	To determine the method used to calculate congestion fees	The ESB is considering three main options for the foundation of the calculation of the fees: • Estimate the value of access to the RRP • Estimate of the total cost of congestion caused by the connecting generator • Estimate of the long run incremental cost of future transmission investment as a result of the generator connection. This design choice will affect how widespread the fees are, and the amount of money at stake.
5.4.2	To determine the process for calculating the fee	The design choices relate to: • when in the connection process the fee should be calculated, balancing the need for upfront clarity for investors and accuracy in calculation • the balance between simplicity and accuracy in designing the calculation process • the term of the modelling and congestion cost analysis • whether the fee should aim to address all congestion or only intra-regional congestion.

5.4.1 Method used to calculate fees

The metric used to calculate congestion fees is a critical design choice as it determines how widespread the fees are, and the amount of money at stake. In selecting a method to calculate fees, a core underlying question is whether the fees should:

- provide an efficient signal to all connection applicants, including those who are connecting in accordance with the ISP – this is likely to give rise to fees that start out low and rise gradually as new generators connect in a given location; or
- only be applied to projects that wish to connect in excess of planned levels for a given location. This is likely to give rise to higher fees that take effect only after a pre-determined threshold is met.

The former is likely to provide a more efficient price signal but would mean that at least some fees would be levied on generators that are connecting consistent with the ISP. In contrast, the latter is likely to send less efficient signals, but provide lower fees to those connecting consistent with the ISP and higher fees to those not connecting consistently with the ISP.

In light of these varying objectives, the ESB is considering three main options to provide a foundation for the calculation of fees:

- estimate the value of access to the RRP
- estimate of the total cost of congestion caused by the connecting generator
- estimate of the long run incremental cost of future transmission investment as a result of the generator connection.

Each of these measures capture a financial impact of the proposed project rather than a physical measure such as the percentage of output from the project expected to be constrained due to congestion. Financial measures are considered the most appropriate as they capture impacts which are critical commercially and which reflect the economics of congestion.

Each of these measures also requires a decision as to whether the project seeking connection replaces generation of a similar location, size and timing in the ISP or is additional to the ISP. That decision will impact on the fee determined in each of the three options as outlined in the following.

Estimate the value of access to the RRP

To provide the correct economic signal, the congestion fee should reflect the forecast net present value (NPV) of the connecting generators' access to the RRP. If calculated accurately then a generator will face an investment signal that reflects marginal congestion costs. Ideally, the connection fee would reflect:

> *Congestion fee = NPV sum over dispatch intervals [forecast marginal cost of congestion x forecast G_{NEM}]*
>
> *Where*
>
> - *Forecast marginal cost of congestion = forecast RRP – forecast LMP in the dispatch interval in question and*
> - *Forecast G_{NEM} = the generator's forecast dispatch in the energy market for the dispatch interval in question.*

That is, the congestion fee should equal the sum of the marginal cost of congestion caused by the generator, to the extent and at those times that the generator gains access to the RRP in the energy market.

When the generator doesn't gain access to the RRP (ie, $G_{NEM} = 0$), the generator is already paying for the congestion it causes in real time through the CRM. The formula above reflects the principle that to promote economic efficiency, the generator should pay once, and only once, for the congestion it causes – either in real time through the CRM or ahead of time via the congestion fee.

Estimating G_{NEM} will need to take into account expected real-world bidding behaviour in the energy market especially in regard to market floor price bidding.[44]

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44 I.e., bidding at -$1000/MWh in the event that a generator that is in-merit versus the RRP is positively participating in a binding constraint

The forecast LMP would be derived from a cost-reflective dispatch model. It would also need to take account of future transmission and generation investment outlined in the base case derived from the ISP. A determination would need to be made as to whether the generator being assessed substitutes for generation in the ISP (i.e. is consistent with and part of the ISP) or additional to the ISP. If it is consistent with the ISP, the congestion fee should be relatively low as the connection should be efficient.

There is also a question as to whether the fee is aiming at addressing all congestion or only intra-regional congestion. Generators already face inter-regional congestion costs, which manifest in differences between the RRPs across regions. Hence, there seems to be no need for a fee to reflect inter-regional congestion costs.

Estimating the marginal cost of congestion and G_{NEM} is a complex process. In general, we might expect that areas of the grid that are congested would have relatively high fees, while areas of the grid that are uncongested would have low fees. That said, a generator in a heavily congested area with a high coefficient in the relevant constraints could end up with a *low* congestion charge, because the model anticipates that they will be frequently curtailed (and hence the value of access is low). The overall efficiency of the approach would then be reliant on the project proponent also taking into account its likely curtailment as well as its congestion charge in making a decision as to whether the project should proceed.

These outcomes are a product of complex and dynamic power system flows, and over-reliance on detailed, long term power system models may give spuriously accurate results. A trade off will be required between accuracy and simplicity/timeliness. A pragmatic approach may be to give the relevant planning authority (e.g. AEMO) flexibility to develop and maintain a methodology for calculating congestion fees that provides appropriate locational signals with respect to congestion.

While it is useful to understand the theoretical ideal, in practice, it may be preferable to adopt a more generalised approach that results in:

- high fees in parts of the grid that are already congested,[45]
- low/no fees in parts of the grid that are uncongested, and
- incentives to optimise the network impact of projects in parts of the grid that are reaching their efficient hosting capacity.

Notwithstanding the challenges involved, it should be noted that the current arrangements effectively stipulate a congestion fee of zero; anything more accurate than that would improve investment efficiency relative to the status quo.

Estimate of the total cost of congestion cause by the connecting generator

This approach estimates the total cost of congestion caused by the connecting generator by comparing the forecast cost of constraints under the base case derived from the ISP optimal development path[46] to a sensitivity that takes into account the new generator. Congestion costs would be modelled under four scenarios:

45 Or parts of the grid that are forecast to become congested following the connection of REZ generators.

46 The ISP optimal development path comprises both transmission projects (which can be either actionable ISP projects or future ISP projects) and ISP development opportunities (including new generation and storage).

	Base case derived from the ISP optimal development path	Base case including the proposed generation investment
NPV of dispatch costs assuming no constraints, summed over future dispatch intervals	1	3
NPV of dispatch costs including constraints, summed over future dispatch intervals	2	4
NPV of total cost of congestion	(2 – 1)	(4 – 3)

The difference between sensitivity 1 and 2 would be the NPV of the current total cost of congestion that is forecast to occur under the ISP optimal development path under the most likely scenario. The difference between sensitivity 3 and 4 would be the NPV of the total cost of congestion after the generator has connected. All other inputs and assumptions would remain unchanged. In turn, the difference between (4-3) and (2-1) is the change in the total cost of congestion caused by the connection.

Again a decision needs to be made as to whether the proposed new generator should be treated as is connecting accordance with the optimal development path and hence part of the base case or whether it is additional. If it was deemed to be consistent with the ISP, there would be no difference between the base case and the sensitivity and hence the congestion fee would be zero. If it was larger, different technology or delivered at a different time, then a fee would result. Once sufficient new generation has connected to a given location to align with forecast ISP development opportunities, any subsequent new generators would face a fee that reflects the full impact that their location decision has on system-wide congestion.

This methodology means that congestion fees would only come into effect after the generation forecast in the ISP has already been built. Given that the ISP forecasts a need for 135 GW of new utility-scale VRE capacity by 2050, we would expect congestion fees to be levied relatively infrequently. However, it provides a tool to signal to investors to connect in locations that are more consistent with the investments being made in the grid.

For those generators who choose to locate in excess of ISP forecast levels at a given location, this methodology for calculating congestion fees is likely to result in higher fees than the alternative option (estimate the value of access to the RRP). This is because it calculates the total cost of congestion, including the congestion costs incurred by the new connecting generator who is paying the fee and the increase in the congestion costs of all other generators resulting from their connection. Hence it is likely to provide a strong signal to discourage such investments.

Long run incremental cost

The long run incremental cost (LRIC) method attempts to value the NPV of the increase in network expenditure required to provide a defined level of generator access with the new generator connected to the system.

A critical input to the LRIC calculation is the planning standard which is used to determine the level of access that TNSPs are required to provide to generators (since this drives the costs of providing that standard). An access standard could be defined on either an economic or a deterministic basis. Given such a standard, a base case is required setting out the future development and cost of the grid. Where a generator connects to the grid, the nature, cost and timing of the incremental investment required to maintain this standard would need to be calculated and the NPV of the costs determined.

This would be administratively burdensome and means that a method is required to estimate the LRIC in practice.

Previous attempts[47] to develop an LRIC methodology occurred in 2015, before the ISP took on its current role in setting the optimal development path for the power system. Given the complexity of these calculations, the AEMC proposed a simplified model using a deterministic planning standard. However, the character of VRE generation makes simplification of the planning standard difficult. For instance, deterministic planning standards typically focus on outcomes under peak demand conditions, which are not well suited to the needs of variable renewables.

Given the subsequent upscaling of AEMO's capacity to undertake whole-of-system planning, an economic approach to calculating LRIC may be more feasible now than it was in in the past.

An economic planning standard is encapsulated in the ISP and RIT-T methodologies. The level of access granted to the generator would be consistent with the level of access that would arise under the optimal development path. If this approach was applied to the LRIC calculation, AEMO (or another body such as the TNSP) could run an ISP-style calculation with and without the new generator and calculate the change to the net present value of the recommended transmission expenditure because of the generation investment.

Again, to the extent that the generation investment is consistent with the ISP's optimal development path, the two scenarios would be identical and so the congestion fee would be zero. Where investments differ from the ISP, and so prompt additional transmission investment immediately or in the future, the fee would be positive.

Given the scale of the ISP modelling task, it would be critical to establish and resource arrangements to keep the model up to date throughout the ISP cycle and allow for its use in this context. It would be necessary to specify which ISP inputs and assumptions need to be kept up to date within the ISP cycle (for instance, new committed projects and retirements) and for a version of model to be available for use as part of the connection process, either by AEMO or the TNSPs. It would also be important to have enough information in the public domain to enable prospective investors (or their consultants) to replicate the results.

Question for stakeholders

Q13. Which of the proposed metrics do stakeholders consider should be used as the basis for calculating congestion fees? Are there alternative metrics the ESB should consider?

5.4.2 Fee calculation process

This design choice relates to the process used to calculate congestion fees (which involves an assessment of the impact of a project on congestion). There are trade-offs between:

- providing upfront certainty to investors versus reflecting the fast-changing nature of the power system and hence efficiency of a proposed project
- accuracy versus transparency
- calculating congestion impacts over the life of a project to reflect long term costs with the risks and uncertainties of the long-term power system development.

47 AEMC (2015) Optional Firm Access Final Report, Volume 2, Chapter 6 and Appendix C.

Timing of fee calculation

There would be advantages in developing pre-defined connection fees which would be known to potential investors well in advance of their connection. However the impacts of a project on the grid will be dependent on the specifics of the proposed connecting plant and hence:

- The scale of the project
- The technology or mix of technologies proposed and hence the profile of its use of the grid
- The detailed location of and connection to the grid
- The timing of the project and hence other generation connected, or already committed to connect, to the grid at that time.

The congestion fee seeks to provide an efficient cost signal and hence needs to reflect those factors. Ideally there would be options available to optimise a project costs, including options to modify their project or make investments in the grid which would reduce its impact on network congestion and have this reflected in a lower congestion fee. Options to reduce congestion impacts are explored in section 5.8. These options are dependent upon a bespoke process for each connection applicant; they would not be possible if we were to adopt a pre-determined fee calculated on a simplified, non-specific basis.

The ESB seeks feedback on the proposal that the connection fee should be a bespoke calculation on the specific project made late in the connection process, but prior to final commitment by the proponent. Given the actual fee under such an approach would not be precisely known until late in the project development, market participants need to be well informed earlier in the process to assist them to identify the most prospective projects for development and to be able to optimise their projects. The provision of information is addressed in chapter 6.

Process for calculating congestion fees

In addition to making the choice as to when a congestion fee is calculated, there are design choices related to the calculation process – balancing simplicity with accuracy. A simpler approach reduces the resources required to calculate the fee, both for the connecting party and the TNSP or AEMO. However, there will be congestion in an efficient grid with a diverse mix of renewable generation and storage used to meet customer needs. A simpler process could send general signals to potential investors as to the attractive locations to connect but would not reflect the different impacts due to scale, technology type and design of the connecting plant.

When there is some congestion in an area, the connection of additional generation is likely to have a significant and non-linear impact on congestion. That impact will be very dependent on the scale of the project. The impact will also be sensitive to the mix of technologies proposed for the project whether wind or solar or some hybrid mix of the two perhaps also with battery storage.

Connection applicants should have an incentive to design their proposed plant in a way that takes into account impact on congestion. Modifying their connecting plant by incorporating an efficient mix of different types of generation plus storage or by optimising the connected nameplate capacity of each component with the maximum output through the connection would be effective options in this regard.

The congestion fee should accurately reflect these differences to drive parties to develop the most efficient projects. This argues for a more bespoke calculation process.

While a more bespoke approach is proposed, the process for determining the congestion fee needs to be as predictable and transparent as possible. This suggests that the market modelling should be prescribed clearly in guidelines, based on cost reflective bidding by participants, limited to a single base case and undertaken for a limited number of years.

This would reduce the resources needed to calculate the fee and minimise the risk that the fee calculation process would extend the time to receive an offer to connect. A single base case should also be adequate to appropriately drive the project optimisation process undertaken by the proponent as it should reflect project relativities with sufficient accuracy.

Term and scope of the modelling

The term of the modelling and congestion cost analysis also needs to be determined. A long period of time would better reflect the lifetime cost of congestion but there are many uncertainties in longer term modelling, especially in the context of the major transition the NEM will be going through and the range of likely technical innovation as part of the international response to decarbonisation. A balance therefore needs to be struck between providing realistic signals while not over-stretching the modelling task.

Question for stakeholders

Q14. Noting the trade-off between investor clarity and accuracy, do stakeholders have feedback on how bespoke the modelling should be?

5.5 Parties subject to the access arrangements

Section 4.2.1 outlined that scheduled and semi-scheduled generators, scheduled load and scheduled storage would be able to participate in the CRM. It is proposed that these same parties would be either allocated a queue number or be required to pay a congestion fee on connection depending on which approach is adopted.

This approach is consistent with the current arrangements in the NEM where these are the parties who are constrained when necessary to maintain the security of the transmission network and hence who are centrally dispatched. Non-scheduled generators and distributed resources are provided full access to the network by their omission from central dispatch. With congestion expected to increase and access effectively ‘priced’ through a congestion fee or a priority queue number, there may be a growing incentive to connect a number of non-scheduled projects rather than larger scheduled projects. The effectiveness of the chosen approach should be monitored to ensure this does not become a problem and, if so, to consider tightening the definition of non-scheduled plant.

Market participants that alleviate constraints (including storage and scheduled loads)

Scheduled or semi-scheduled resources can by their location or characteristics exacerbate or alleviate some constraints. A market participant which alleviates a constraint will be reflected by a negative coefficient in the relevant constraint equation, i.e. its output will relieve a constraint and allow more generation from others. With a negative coefficient in a binding constraint, they have an LMP which is higher than the RRP.

To avoid duplication, the signal that is provided in investment timeframes should be designed having regard to the arrangements that apply in operational timeframes. As a general principle, a market participant should pay or be paid once for any congestion it exacerbates or alleviates, either through the congestion fee or through the CRM. In turn this will send efficient investment signals. This means that:

- If they are not paying for congestion in real time (because they have been granted access to the RRP) then they should instead face the expected cost of that congestion via a connection fee.

- If they are paying for congestion in real time (because they have not been granted access to the RRP) then the congestion fee should reflect this i.e. the fee should not reflect the real-time congestion
- If they are being paid to alleviate congestion in real time, they should not also be paid to do so via a (negative) congestion fee.

The consequence of this principle is that the congestion fee should reflect the rights and obligations of storage and scheduled loads to participate in energy dispatch. The design choices for the treatment of market participants that alleviate constraints in operational timeframes are considered in sections 4.2.4 and 4.3.3.

Market participants that connect to the distribution network

Distribution network service providers have sought clarity on the treatment of generators that are connected to the distribution network. Ideally, the regulatory framework should be neutral with respect to incentives to connect at the transmission or distribution level.

If the priority access variant were to be adopted, any distribution connected scheduled or semi-scheduled generators would need to be allocated a queue number (given that they participate in the energy market). It may be necessary to use the generator's Transmission Node Identifier as a proxy for the purposes of assigning a priority queue number.

If the congestion fee variant were to be adopted, it seems appropriate for distribution-connected scheduled and semi scheduled generators to also pay a congestion fee that aligns, in principle, with the fee faced by transmission connected generators. However, given that this review has focussed to date on transmission, a separate Rule change process would be required to properly consult stakeholders on these changes.

5.6 Integration of access with the connections regime

By design, the access regime (whether the priority access or congestion fee variant) provides signals that influence investment decisions. These signals will vary over time as available transmission capacity is used up by new projects. Whether the priority access model or congestion fee model is ultimately selected, it is necessary to consider the timing of the process to determine the queue position or finalise the congestion fee relative to other steps in the connection regime. Investors should receive their locational signals in a timely fashion, but not too early – since we do not want to confer valuable access on projects that are unlikely to proceed.[48] There may be a role for batching, qualifying criteria, and/or use it or lose it provisions.

Section 5.7.1 summarises the existing transmission connection process under the NER. The following sections set out how both the priority access and congestion fee models interact with the connections regime, which are summarised as follows:

48 This issue manifests differently under the two model variants. In the congestion fee variant, the issue is primarily about being able to accurately calculate the fee. If a project does not proceed, there is only an issue if another project's fee has been calculated on the assumption that the failed project goes ahead. In the priority access variant, the process timing could determine the position in the queue. Projects will prefer to be assigned queue position earlier, but that could lead to queue numbers being given to projects that don't proceed, or even speculative projects where progress is uncertain. That creates associated uncertainty for other, bona fide, entrants.

Section	Description	Design choice
5.6.1	To explain how the access arrangements would interact with the connections regime	Whether a queuing or congestion fee variant is selected, a key design question is how and when the queue number or congestion fee for a connection applicant is determined. This requires the assessing and finalisation of these parameters to be integrated into the connection process.
5.6.2	To consider the timing of finalising the queue position or congestion fee	This section considers at what point within the connections process the access arrangements would take effect.
5.6.3	To consider how to manage multiple simultaneous connections under the access arrangements	There may be several parties seeking connection within the same area of the network at the same time. To manage this, design choices include: o Batching simultaneous connection applications o Auctions to determine who obtains access
5.6.4	To consider the qualifying criteria for parties to obtain access	Qualifying criteria needs to balance ensuring only projects which have a high likelihood of proceeding obtain a preferential queue position or favourable congestion fee while ensuring we do not unnecessarily restrict competition.
5.6.5	To consider how to avoid third parties securing favourable access they will not use	It is proposed that the congestion fee or queue position would have a limited validity period. The ESB seeks feedback on this proposal as well as the appropriate duration of any validity period.

5.6.1 The connections process

The connections process in the NEM is complex and has been subject to a number of reviews. The national grid is long and varies from a strong network in some areas, often areas where thermal generation has been concentrated in the past, and weak to very weak in others, often where new generation is seeking connection. The evolving technology of asynchronous plant and our understanding of its performance has also been a complicating factor. The connection process allows for the variable characteristics of the grid by providing for a bespoke process and ability to negotiate technical standards within bounds. This has meant the connection process can be fraught.

The ESB notes that the Clean Energy Council and AEMO are currently collaborating on the Connections Reform Initiative.[59] This should assist in streamlining the process and reducing problems post the connection process. However, the basic framework remains. Given the nature of the process and the potentially extended timeframe involved, integration into the connections process is a design consideration for any access initiative targeting the investment timeframe.

The current process does not formally establish a connection queue although the assessments of connections applications can be very dependent on the projects timing relative to other proposed projects in the same area. The Rules establish a process of a *connection enquiry* in NER 5.3.3 with time limits on certain steps. The *connection enquiry* establishes the information required to proceed with a *connection application* under NER 5.3.4. NER 5.3.6 then aims to provide a timeline to be met to assess the application and make an offer to connect.

These process timelines are all subject to timely and complete information provision. It is important to note that a project proponent will have a number of processes running in parallel to the connection process to obtain development approval, approval from equity and debt providers, selection of contractors and vendors etc. This can make the process to gain a connection agreement more convoluted and also make it more difficult to follow the timeline set under the Rules.

5.6.2 Timing of finalising queue position or congestion fee

Whether a congestion fee or queuing approach is adopted to managing congestion in the investment timeframe, the timing of the finalisation of these parameters within the connection regime needs to be considered.

Issues related to establishing the queue position of a project are addressed in section 5.3.2. In the priority access model, the process timing is critical as it could determine the position in the queue. Projects will obviously prefer to be assigned queue position earlier, but that could lead to queue numbers being given to projects that don't proceed, or even speculative projects where progress is uncertain. That creates associated uncertainty for other, bona fide, entrants. It is therefore important to ensure that those generators that are assigned queue position have a high probability of progressing as claimed. This needs to be balanced against the proponent's need to have confidence in the final queue number allocated to the project ahead of making a final commitment.

Design choices in the process of calculating the congestion fee are addressed in section 5.4.2. That analysis suggests that a bespoke calculation late in the connection process would be likely to give the most efficient fee that reflected the impact on network congestion of the project. In practice, project developers may wish to explore multiple fee calculations, under alternative project designs, so that they can optimise their design.

We propose that connection applicants receive an indicative queue position and/or congestion fee in response to their connection application, with the outcome to be finalised upon completion of the connection agreement. Applicants who are at the connection enquiry stage should be able to receive an indicative quote for a fee. The indicative quote would be based on specified assumptions regarding the timeframes for completion of the project. Other elements of the framework would aim to provide early information[49] to assist in choosing to advance projects which are likely to be attractive and to provide options for how that project might be optimised to maximise its value.[50]

Questions for stakeholders

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

5.6.3 Managing multiple simultaneous connection applications

There are potential issues with an approach where there is a benefit in being 'first in' – both for the calculation of a congestion fee or the allocation of a queue position. Those issues are likely to be of most concern in areas where there is strong interest for connection from a number of proponents.

49 See chapter 6

50 See section 5.8.

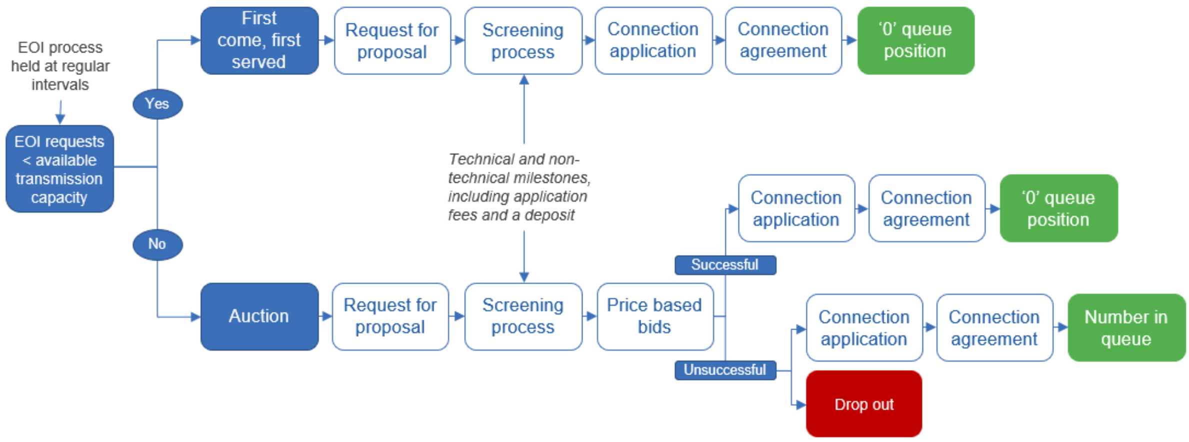
One option would be to establish a process to join applications together into a batch process where each project in that batch would progress through the connections process simultaneously and have the same queue position or simultaneously calculated connection fees. A batching approach has some attraction and is being considered as a potential outcome of the CEC/AEMO connections reform initiative.

A batch process could be very relevant to the development of a REZ or at least each stage of a REZ development. The process for establishing a batched process in other cases is not clear nor how it might integrate with the connections regime. An option would be to advise the market when a connection enquiry or connection application is received and seek expressions of interest by other parties in connecting to the same area. This though would delay the commencement of processing of applications but may improve the assessment process and time to deliver offers to connect. If there was interest by multiple parties to connect in the same location, it is unclear how a batching process could resolve access where those applications exceeded the likely hosting capacity.

Alternatively, where it was evident there were multiple parties interested in connecting to an area of the grid, an auction could be held to resolve who obtains access. A potential approach could be to declare a REZ and undertake an auction for access under similar terms as would occur with other REZs in that jurisdiction. The auction approach could set the congestion fee through the auction or assign the same queue position to parties who are successful in the auction. This should incentivise the best projects to connect rather than the earliest project. However, if held on an ad hoc basis, a 'pop-up REZ' type process may introduce an unacceptable delay in dealing with applications to connect.

An alternative approach could be to establish a regular process to assess whether an auction is required. For instance, Castalia proposes that AEMO[51] conduct annual reviews of whether spare transmission hosting capacity is available, and if it is, conduct an Expression of Interest (EOI) process (Figure 26).

Figure 25 Auction-based method for managing multiple connection applications



Source: ESB analysis of Castalia proposal[52]

51 The ESB notes that this function could also be carried out by a jurisdictional planning body.

52 Castalia, Rethink of the Open Access Regime, February 2022, p.27-30. Available at: https://ceig.org.au/wp-content/uploads/2022/02/2022-02-23-Report-on-Transmission-Access-Reform.pdf

If the proposed generation capacity put forward in the EOI proposals is less than available transmission hosting capacity, AEMO would apply a first come first served approach. Eligible projects would be invited to submit a request for proposal (RFP), and so long as their project progresses through the connections process in a timely fashion, they would receive a priority queue number.

If the generation capacity of submitted EOIs is greater than the available transmission capacity, AEMO would perform a batch study of all RFPs and filter out applications that are not eligible to proceed to the next round of the tender process based on technical and non-technical criteria. The successful applicants will be invited to participate in the auction and submit their price proposals. Up to the point where the capacity of local transmission is reached, bidders would be assigned a number of zero. Bidders higher in the ranking order will then receive a queue number according to their ranking.

If an auction-based method were to be applied in the context of a congestion fee, the auction process would replace the congestion fees when there were multiple parties seeking to connect in a location with spare hosting capacity available. If an unsuccessful auction participant still wished to proceed, they would need to pay a higher congestion fee that takes into account the presence of successful auction participants' projects.

Questions for stakeholders

Q16. Should there be a process for batching connection applications and jointly establishing connection requirements and fees?

Q17. Could an expression of interest process, combined with auctions, be used to manage multiple simultaneous connections?

5.6.4 Qualifying criteria

Consideration needs to be given to the need for qualifying criteria for parties receiving a queue position or seeking to lock down a congestion fee. It is suggested that the queue position would be provisionally identified at the time a *connection application* was made and confirmed at the time the connection agreement was signed. Similarly, the congestion fee is proposed to be finally determined at the time the connection agreement is finalised. To progress through the connection process in a timely manner, the project must be well defined and key equipment identified. This will ensure projects have some financial commitment but may not be much beyond that.

Criteria could be set beyond these technical information requirements to ensure the validity of the project. Those qualifying criteria might include financial criteria (availability of equity and debt), contractual backing for the project output or even the lodgement of a bond. Any qualifying criteria would need to balance ensuring only projects which have a high likelihood of proceeding agreement obtain a preferential queue position or favourable congestion fee with ensuring we do not unnecessarily restrict competition.

Questions for stakeholders

Q18. Should there be conditions precedent which must be met before a queue position or congestion fee is finalised and accepted? If so, what sort of measures would be appropriate?

5.6.5 Use it or lose it

There is little need for use it or lose it in the case of a connection fee if the fee is finalised at the time of the connection agreement.

However, an early application to connect could ensure a favourable queue position in the priority access option.

This then raises the potential for third parties to secure favourable positions for projects they hope to hold or on sell rather than implement. Developers trading in projects is common and does not raise efficiency concerns. However, developing notional projects and squatting on those associated access rights will likely raise costs without providing any benefits to customers.

To prevent such actions, it is proposed that the queue position would be finalised close to the time of finalising the connection agreement and would have a limited validity period; i.e. once determined, there would be a time period within which the connection fee or queue position was accepted and the project committed. If not committed within a reasonably tight period, the project would lose its queue position and have to reapply for a new one. If this type of process was not included, it would disadvantage subsequent projects and drive incentives for parties to define projects and then hold those to on sell later. The validity period needs to be determined but we note that the CEIG suggested 2 years.

Questions for stakeholders

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

5.7 Treatment of incumbents

As access is determined by the physical capacity of the transmission system, it is necessarily finite. Accordingly, implementing an improved access framework naturally involves policy decisions around the allocation of value between different market participants and whether this varies from outcomes under current arrangements.

This section outlines how access is allocated under the current framework, and how this compares to the two hybrid models under consideration (congestion fees and priority access). Under both models, the access of incumbents who are already connected to the system at the time the new framework is introduced could be better protected from erosion by new entrants over time. However, questions remain in relation to the appropriate extent of such protections and how long they should remain in place. The design choices are summarised as follows:

Section	Description	Design choice
5.7.2	To determine the treatment of incumbents in transitioning to the priority access variant	The “grandfathering” options under the priority access variant consider whether: • The queue position allocated to incumbents should expire after a given time period • The queue position allocated to incumbents should gradually increase over time • The initial queue position allocated to incumbents should be adjusted to reflect transmission expansions • Incumbents should have the option of paying to maintain their queue position.
5.7.3	To determine the treatment of incumbents in transitioning to the congestion fee variant	The ESB is considering: • Whether the “protection” of incumbents should be factored into the fee calculation for new entrants • If so, how to determine the appropriate degree of protection • How to implement consistently across all incumbents.

5.7.1 *Current arrangements*

Under the existing access framework, generators' access to the RRP is determined on the basis of physical dispatch calculated by the NEM dispatch engine (NEMDE). NEMDE's objective is to meet demand at the lowest cost, whilst maintaining system security and avoiding violations of constraint equations. Each generator or interconnector represented in a constraint equation has a coefficient which reflects the impact it has on the transmission system. If competing generators respond to congestion by all bidding the market floor price in an attempt to be dispatched, their bid prices are the same so their coefficients will determine their level of access. Specifically, if there is only one constraint equation binding (causing congestion and restricting the dispatch solution), NEMDE minimises the cost of generation by dispatching generators with the lowest coefficients first. This feature of dispatching bids tied at the market floor price based on generator coefficients gives rise to "winner takes all" outcomes.[53]

The winners and losers associated with coefficients vary over time, as generators enter and exit the market, generation availability and demand patterns change, and AEMO's constraint equations change to reflect these events. This means that under the status quo, the access of incumbents in the market today can be eroded by new entrants with more favourable coefficients.

If the CRM were to be introduced in isolation, these outcomes would persist. This is because the initial dispatch run to allocate access would continue to reflect the "winner takes all" outcomes described above. Further, the access granted to incumbents under the CRM model could still be 'cannibalised' with the subsequent connection of new generators. As outlined below, the two hybrid models could both provide a relatively higher degree of protection for incumbents, depending on the implementation approach.

5.7.2 *Treatment of incumbents under the priority access variant*

This variant envisages the introduction of a queuing mechanism to provide priority access for generators in line with their queue position. As discussed in section 5.3, there are various options for the allocation and duration of queue positions. These issues must also be considered for incumbents.

The ESB is considering whether, at least as a transitional measure, it would be appropriate to allocate all incumbent generators a position at the front of the queue (i.e. 'queue position zero'). While incumbents hold this queue position, and new entrants are unable to also obtain it, incumbents' current level of access to the RRP would be preserved. This is because the queue position will ensure that in the initial dispatch run, incumbents receive access ahead of new entrants with higher queue positions (i.e. access ahead of those further back in the queue).

However, as noted above under the status quo incumbents have no guarantee that their current level of access will be preserved over time as new generators connect. Therefore, allowing incumbents to maintain a queue position of zero in perpetuity may provide windfall gains because the level of access will no longer be subject to 'cannibalisation' from new entrants, as it is today; indeed, their level of access may even improve over time with investment in the transmission network. Further, preserving current levels of access for incumbents would come at the expense of new entrants' ability to be dispatched in the energy market.

Accordingly, the ESB is considering a range of options for the treatment of incumbent generators:

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53 A more detailed explanation can be found in Section 2.2 of the ESB's May 2022 Transmission Access Reform Consultation Paper

1. The queue position allocated to incumbents upon introduction of the new access framework could expire at a specified date. The ESB has identified several options for further assessment, including: a common pre-determined date for all incumbents, potentially set with reference to a typical contract duration period (i.e., with a view to preserving their ability to back existing contracts); and a bespoke term, potentially set with reference to an incumbent's retirement date as specified in the ISP or their announced retirement date.
2. Incumbents, or certain types of incumbents such as fossil fuel generators, could not receive grandfathered rights. In this case, they could be required to participate in an auction if the wish to obtain the benefit of a high priority position at the front of the queue. If they do not participate in the auction, or they are outbid, then the incumbents would be allocated a position at the back of the queue.
3. The queue position allocated to incumbents could gradually increase over time to reflect the erosion of access that might be anticipated under the status quo. For instance, under the tiered option, incumbent generators may start out with primary access, which becomes secondary access after 5 years.
4. The queue position allocated to incumbents could gradually dilute over time by including a pre-determined quantity of new generation capacity within the same queue number or tier. This approach could address the system-wide shifts in the efficient level of congestion that occurs as the power system transitions to higher levels of VRE.
5. The initial queue position allocated to incumbents could be adjusted to reflect transmission expansions, in order to avoid a windfall gain associated with *improving* their level of access beyond their position at the time the new access arrangements are implemented. The ESB notes that this is complex, as incumbents may have factored in expectations around future transmission expansions in their investment decisions.
6. Incumbents could have the option of paying to maintain their queue position, and if so how this would interact with the broader approach to allocating queue positions. If they opted not to pay, they would be sent to the back of the queue.

Question for stakeholders

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

5.7.3 Treatment of incumbents under the congestion fees model

This model aims to provide efficient investment signals for new entrants by introducing a connection fee that reflects the availability and value of access in different parts of the grid. The connection fee would apply to new entrants, but not to existing generators.

From the perspective of incumbents, relative to the status quo, this provides a higher level of protection from the risk that their existing level of access is eroded by future new entrants. This is because the connection fee would disincentivise inefficient investments which cannibalise the access of incumbents. However, it is still possible that new entrants would choose to connect in constrained parts of the network – and gain access at the expense of incumbents through the CRM by having a more favourable coefficient. This will ultimately depend on the level of the congestion fee and how this affects the relative attractiveness of different locations for new entrants.

As discussed in section 5.4, various factors may underpin the approach to setting the connection fee. Once a generator reaches their modelled (or announced) retirement age, they would be excluded from the transmission planning studies used to calculate the connection fees.

This means that connection fees would be set at lower levels in proximity to end of life generators, with the result that they could expect to be crowded out by new entrants.

Question for stakeholders

Q21. Do stakeholders support the calculation of congestion fees reflecting the protection of incumbents under the model? If so, do stakeholders have feedback on feedback on how to determine the appropriate degree of protection?

5.8 Options to reduce congestion impact

Connection applicants may value options that give them flexibility to reduce their exposure to a congestion fee or unfavourable queue position. For instance, there may be opportunities for a connection applicant to fund an incremental investment in the shared transmission network in return for a lower fee, or improved queue position. Alternatively, a connection applicant may be willing to accept arrangements whereby their access is limited before other generators. Flexible options for generators to reduce their congestion impact (in return for an improved queue position) was a core element of the TQM proposed by the CEIG.

The following sections discuss how both the congestion fee and priority access variants could allow connection applicants to reduce their exposure to congestion in the network (via the congestion fee or an unfavourable queue position, respectively). The ESB seeks stakeholder feedback on how the models can be designed to promote such an option for connection applications:

Section	Description	Design considerations
5.8.1	To consider the ability for participants to fund transmission investment	The ESB's access reform model could provide an opportunity for connecting parties to realise a benefit from, and therefore contribute to, shared transmission investment.
5.8.2	To consider the ability of participants to fund storage to alleviate their congestion impact	A generator can reduce its congestion impact by funding storage behind the meter of its generating plant or by contributing to a merchant storage asset in the vicinity.
5.8.3	To consider how participants could accept reduced access	The ESB is open to arrangements that allows a connection applicant's access to be limited before other generators, where they are willing to do so.

5.8.1 Funded transmission

Current arrangements for planning and investing in transmission

As transmission is a network monopoly that is also an essential service, the National Electricity Rules establish a regulatory process to decide where and when investment in transmission infrastructure should occur.

The plan driven approach to network development aims to deliver the grid that efficiently meets the needs of customers and network users as a whole. The regulatory incentive schemes seek to drive efficient maintenance and operation of that grid and provide an opportunity for TNSPs to benefit where they can find targeted projects that deliver additional benefits.

However, other parties, particularly market participants seeking to invest in generation or storage connected to the grid, may consider other enhancements to the grid are justified based on the benefit to their projects; i.e. projects which provide a commercial benefit to the proponent but may not provide benefits which exceed the cost for all network users. While such investments are theoretically possible, they rarely occur in practice because a market participant receives no rights over the assets they fund.[54] With different incentives, they may also identify additional opportunities to improve the ability of the grid to host their proposed projects. The ESB hybrid model set out in this paper seeks to drive efficient connection to the grid. We are considering how the model can provide opportunities, where appropriate, for parties to invest in improvements to the grid over and above that provided through the regulated regime.

Opportunity for generator-funded investment in transmission

The NEM has a long history of attempting to offer opportunities for market participants to fund additional investment within the regulated, shared network. While there has been some limited use of provisions to negotiate with the relevant TNSP to fund investment in the shared network, the arrangements have been ineffective in the broader construct of the current access regime, as there is no structure to provide any specific access right to any party. This meant that a participant could fund investment but had no particular right to use that asset over other participants or new entrants.

The arrangements were reviewed several times over the years and some specific provisions were actually removed from the Rules as a result. The ESB is open to views as to how opportunities to participants to invest in grid enhancement might be made possible.

The key limitation on participants making investments in the shared grid is the inability for them to receive a private benefit for any additional capacity they provide. The ESB considers that the congestion fee or priority access variants may be designed in a way that provides an opportunity for connecting parties to realise a benefit from investment in the shared transmission system.

Given the costs involved, we envisage that generator-funded "enhancements" would take the form of low-cost, incremental investments (as opposed to merchant investment in major transmission assets). Examples of incremental investments include:

- Investment in control schemes
- Targeted investment in plant such as SVCs or impedance control devices to mitigate some constraints and allow the full utilisation of the thermal capacity of the network
- Potential incremental investment in transformer upgrades or line stringing to increase network capacity

Both the priority access and the congestion fee variants provide incentives to connect the right plant in the right location, taking into account the connecting plan's impact on congestion.

Under the congestion fee variant, a connection applicant who agrees to pay for an investment that reduces their impact on congestion could receive a reduced or even negative congestion fee. This would not provide a specific right to any enhanced network capability, but the connecting party would get the benefit of a discount on their fee (acknowledging that the discount would be at least partially offset by the cost of the funded transmission).

54 Except in the case of designated network assets, however this framework only applies to radial network assets due to challenges associated with physical flows on the meshed system. See https://www.aemc.gov.au/rule-changes/connection-dedicated-connection-assets

A bespoke calculation of the connection fee based on the forecast increase in congestion driven by a project would directly incorporate the benefits from such schemes.

Under the priority access variant, then such investment could deliver a higher priority in the queue. This would give the investor confidence that that they will reap the benefit of their investment, rather than having the benefits eroded by subsequent connections.

Risks associated with generator-funded investment in transmission

Even in the case of incremental improvements, there are a number of challenges associated with generator funding of shared transmission assets:

- It's not easy to identify the low-cost improvements due to information asymmetry between the TNSP, the generator and the regulator. TNSPs are best placed to know what opportunities are available, but they not necessarily incentivised to reveal them. Instead they may prefer to pursue a more lucrative larger investment via the regulatory process. The AER has introduced reforms that attempt to address this issue (in particular, the NCIPAP) but imbalances remain. The ESB's plans for improved access to power system information could also address the information asymmetry problem.
- If the regulatory framework succeeds in incentivising TNSPs to reveal the low-cost improvements, there are further challenges in ensuring that generator charges are not excessive given the imbalance in negotiating power, and the bespoke nature of the projects.
- If the scheme is not carefully calibrated, there is a risk that the regime will encourage TNSPs to forum-shop between funding routes; i.e. TNSPs may find it more profitable to charge generators for network upgrades that would otherwise have been funded via their revenue determination.

Care will need to be taken in devising effective arrangements, particularly in how they fit into the connection arrangements, interact with network regulation more generally and address information asymmetries.

To be effective, the Rules and regulatory arrangements would need to be reviewed to ensure the ability to invest and gain the benefit are clear. Those arrangements need to fit into the evolving connection arrangements, maximising the opportunity to develop a more efficient connection without unnecessarily extending the time to develop a connection offer. The arrangements may also need to address the obvious information asymmetry in developing fundable projects given the TNSP is best placed to know what opportunities are available.

The network regulation process and related planning processes are now well established. The revenue reset process and network incentive schemes offer alternate paths to gain regulated revenue for network enhancements. In providing additional, non-regulated sources of revenue, we need to ensure we do not erode the effectiveness of the regulated regime in delivering an efficient shared network while providing parties the opportunity to fund additional (modest) investment where it is efficient for them to do so.

5.8.2 Funded storage

Another way for a generator to reduce their congestion impact is to invest in storage. Depending on which variant is adopted, it may be possible for a connection applicant to reduce their congestion fee, or improve their queue position, by modifying their proposed plant to include storage.

In cases where the storage asset is co-located with the generating plant (behind the meter), the impact of the storage asset could be taken into account as part of the process to measure the congestion impact of the project.

In this case it would be necessary to have regard to the energy-limited nature of storage assets and to consider what incentives (or requirements) are in place to ensure that the asset helps to alleviate congestion in practice. This is because batteries can either alleviate congestion, or make it worse, depending on whether they are charging or discharging. Further, a battery that is already fully charged cannot help to alleviate congestion.

A second possible scenario is where a connection applicant reduces its congestion impact by helping to fund a merchant storage asset in the vicinity (i.e., an asset that is not co-located). This approach has the potential to be more scale efficient since multiple generators can make use of the asset. The ESB is considering whether it is necessary and/or appropriate for the regulatory framework to provide for these arrangements, or whether the CRM is sufficient to support these types of arrangements (via financial contracts with other retailers and generators in the NEM).

One possible outcome is that the same investor separately invests in storage and generation in close but not identical locations. This provides a natural hedge for the generator and storage. The generator could, as per section 5.8.3 below, accept reduced access because it is physically hedged by the storage.

5.8.3 Agree to accept reduced access

Alternatively, a connection applicant may be willing to accept arrangements whereby their access is limited before other generators. Neoen's submission put forward a proposal whereby generators that locate in a congested area could enter into an agreement to offer capacity into the CRM:

> "For example, for a particular connection location, … the efficient generator size is 100 MW; more would cause inefficient congestion. The generator may want to build 120 MW, knowing that transmission will be improved with scheduled works in 4 years. The generator would then have to agree to offer 20 MW into CRM at $0, so other impacted generators can buy back their capacity for a negligible amount."[55]

These types of arrangements potentially have merit and the ESB would like to explore them further. However, there is an issue associated with the Neoen proposal, which is that even if the new generator offers 20MW at zero, demand for congestion relief may be such that the CRM clears above zero (i.e. more than 20MW is cleared). As a result, pre-existing generators won't necessarily be able to access the extra congestion relief for $0.

An alternative approach would be to give the additional 20MW a lower priority ranking (higher queue number) within the priority access variant. The new generator would be entitled to offer 100MW into tier 1 dispatch and then an additional 20MW into tier 2 dispatch. The 20MW bid would only be allocated access to the RRP if there is some transmission capacity remaining after all tier 1 generators had received their full access.

Question for stakeholders

Q22. Should the ESB develop proposals to give generators options to reduce their congestion impact (in return for a lower fee or worse queue position) as part of its congestion management reform package? If so, what options should be included?

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55 Neoen response to the Transmission Access Reform Consultation Paper, pg 8. Available at: https://www.energy.gov.au/sites/default/files/2022-06/NEOEN%20Response%20to%20transmission%20access%20reform%20Consultation%20Paper%20May%202022.pdf

5.9 Governance

It is necessary to consider the governance arrangements. The options under consideration entail a range of new roles and responsibilities, including in relation to the preparation of a congestion forecast methodology, and conducting congestion impact assessments. Depending on which variant is adopted, it would also be necessary to establish a framework to govern the conduct of auctions for priority queue positions, and/or calculating congestion fees.

Section	Description	Design choice
5.9.1	To consider who develops the congestion forecast methodology	Under a congestion fee framework, a central party must be responsible for developing the methodology for forecasting congestion.
5.9.2	To consider who should develop the impact assessment guidelines	Under a congestion fee framework, there is also a need to determine who should develop the impact assessment guidelines, to promote investor transparency and predictability.
5.9.3	To consider who should calculate the congestion fees	Under a congestion fee framework, the ESB must determine which parties will be responsible for calculating the congestion fees.
5.9.4	To consider who would administer the auctions under the priority access variant	Under the priority access variant, there is a need to determine who will be responsible for administering the auctions to allocate queue positions.

5.9.1 Congestion forecast methodology

Under the recently amended system strength framework,[56] AEMO develops the methodology for how to determine system strength requirements at key locations. The System Strength Requirements Methodology includes the process for identifying nodes, modelling future VRE connections and accounting for diversity.

Similarly, under a congestion fee framework AEMO could prepare the congestion forecast methodology. As the whole-of-system planner, AEMO would be best placed to set the assessment approach that all TNSPs are expected to follow. AEMO can also ensure consistency, where relevant and appropriate, with the relevant ISP methodology, which it is also responsible for developing.

5.9.2 Impact assessment guidelines

As noted above, the process for determining the congestion fee needs to be as predictable and transparent as possible for all potential investors. This suggests that the market modelling for assessing a new project's impact should be prescribed clearly in published guidelines.

56 AEMC, National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021, 21 October 2021.

AEMO could also be responsible for preparing the impact assessment guidelines under the congestion fee framework. This is again based on the governance arrangements for the system strength framework, under which AEMO develops the System Strength Impact Assessment Guidelines, which sets out how to NSPs assess the impact of a new connection on system strength.

5.9.3 Calculating congestion fees (some variants)

If congestion fees are introduced, Primary TNSPs may be best placed to calculate the congestion fees for proponents connecting to their respective networks. Each TNSP has the best understanding of its own network, including the state of existing assets, local conditions, upcoming network augmentations and their costs, as well as the plant (including generation and storage) that are in service or committed in the relevant area. The TNSP will also be directly liaising with the proponent as they progress the connection application. The TNSP is therefore also best placed to assist the proponent in understanding how the connection fee has been calculated.

As with other negotiated transmission charges, the methodology for calculating congestion fees would be set out in the TNSP's charging methodology and approved by the AER as part of the revenue determination process. Consistent with its recent process for the new system strength rules, we would expect the AER to update its transmission charging methodology guideline set out the process to be applied by TNSPs.

To ensure consistency in the calculation of fees across the NEM, TNSPs would be required to apply the congestion forecast methodology and impact assessment guidelines developed by AEMO. The information used for the calculations should be consistent with the information each TNSP provides to AEMO under its joint planning responsibilities for the ISP process.[29]

5.9.4 Conducting auctions (some variants)

As explained above, if the queue model is pursued, an auction may be relied on to allocate queue positions to potential participants in areas of the network that are oversubscribed with connection applications. Under such an option, the ESB considers jurisdictional planning bodies that are established under government-led REZ schemes would be best placed to conduct the auctions. As jurisdictions will be leading the development of the REZ, they will set the MW of generation they are seeking to host. As they develop the REZ, they could reserve the MW of generation in the queue (including what is, at the time, at the back of the queue). This may also allow the planning body to inform how the REZ evolves (e.g. with the potential to increase transmission capacity depending on the level of interest in the area).

For jurisdictions that do not have government-planned REZs, the ESB is of the preliminary view that AEMO should run the auctions for the allocation of queue positions. As the whole-of-system planner, AEMO is best placed to consider the generation in the relevant location as well as across the broader network relative to capacity in the network. Further, having one central agency responsible for administering the auctions across the NEM will promote consistency in the surrounding processes for those participating in the auctions. A single responsible agency is also expected to promote efficiencies in administering the auctions.

Question for stakeholders

Q23. Do stakeholders support the proposed governance arrangements?

6 Detailed design choices – investment timeframes – enhanced investor information

6.1 Overview of chapter

Enhanced information is a design choice that enjoys broad stakeholder support.[57] This chapter proposes options for what information could be usefully provided. However, enhanced information is not proposed as a standalone solution as it does not remove incentives for inefficient investment. Accordingly, the proposed hybrid model includes new locational signals for investment.

Regardless of the which model variant is used to incentivise efficient investment, it is important that proponents can predict the likely network access available for different types of projects at different areas in the network. The access available will have a materially, and possibly a critical, impact on the financial viability of the project. Project proponents would ideally have information early enough in development to target projects that more align their interests with efficient system outcomes.

That information could take multiple forms. Different forms of information may be more appropriate at different times in the project development timeline or for different access regimes. Information regarding future congestion in the transmission network could provide direct assistance to proponents through the publication of relevant metrics or may be constructed to assist proponents (or their consultants) to carry out their own detailed network access and market impact assessments.

The ESB seeks stakeholders' feedback on the most valuable information across existing resources and how it can be presented and developed, to establish a single source for investors to access this information to facilitate their siting decisions.

Ultimately, investment decisions need to be made by investors doing their own due diligence. Providing a centralised and readily accessible source of useful information to aid this process can reduce costs for investors and improve their decision-making.

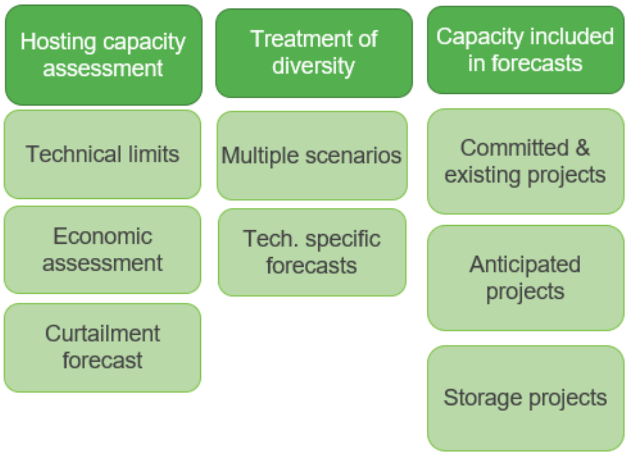
57 Based on stakeholders' submissions to the consultation paper and feedback from members of the Technical Working Group.

Table 19 Design choices for enhanced information

Section	Description	Design choice
6.2	To improve investors' visibility of areas of network capacity	Options for providing investors with an initial screening of the level of congestion in different areas of the network are: • indicative hosting capacity values • making underlying data accessible for investors to conduct their own project-specific market modelling and power system modelling • curtailment forecasts. For indicative hosting capacity values, there is a question as to how to define "zones" of the network and how granular these should be.
6.3	To determine how diverse network conditions should be reflected in hosting capacity assessment	Proposed approach is to calculate a single hosting capacity value for each network "zone", with single assumptions around generation dispatch, load and storage, interconnector capacity and broader network constraints. The alternative is to calculate multiple values for each zone to reflect multiple network scenarios (based on seasonal conditions).
6.4	To determine which network augmentations and connection projects should be captured in the assessment	Future network augmentations and new connections (including generation and storage) can affect the level of hosting capacity. Committed transmission augmentations and connections are proposed to be included in the assessment, overlayed with information about forecast (but not yet committed) projects.
6.5	To determine the method of publishing and maintaining enhanced information	Proposal to publish enhanced information across the NEM in central portal, to be based on existing interactive mapping tools
6.6	To consider governance arrangements around enhanced investor information	There is a role for an agency to develop and administer the central information portal. If transmission hosting capacity values are pursued as an option, there is a need to determine who is responsible for calculating these.

These design choices are summarised in Figure 27.

Figure 26 Detailed design choices – investment timeframes – enhanced investor information



6.2 Hosting capacity assessment

TNSPs are already required to include forecasts of future constraints in their Transmission Annual Planning Reports.[58] However, TNSPs currently use diverse methodologies to fulfil this obligation. In light of this issue, the ESB, together with the Technical Working Group, has sought to clarify what information is most helpful to users, with a view to establishing a consistent NEM-wide methodology for preparing these forecasts. We are also seeking views on whether it would be beneficial to establish a central portal to access this information.

A core area of focus is how TNSPs could calculate values that demonstrate the *indicative* level of capacity in each area of the network to host new generation output. Our intent is that this would provide an initial screening for investors as they consider their project siting options, before they and their consultants undertake their own detailed assessments for their specific project.

There are fundamental limitations of this approach related to the static modelling of transmission hosting capacity. We seek stakeholders' views on whether indicative capacity values would benefit investors to make siting considerations and, in turn, whether it is something the ESB pursues. The ESB has also set out, below, alternative approaches to indicative hosting capacity values for potential consideration. We seek stakeholders' feedback on whether any of these alternatives would be more useful for investors in their initial screening of network capacity than indicative hosting capacity values.

The proposed approach to identify indicative hosting capacity includes:

1. Iteratively apply increasing levels of generation to a connection point or in a certain location, while adjusting interconnector flows within their limits, until a voltage or a thermal overload is observed
2. Capture existing and committed transmission network arrangements
3. Capture existing and committed generation
4. Consider the impact of existing runback schemes
5. Perform the assessment under *system normal* and *single credible contingency* conditions

The output will be an indicative maximum generation capacity that could be connected in each defined location of the network, without breaching existing line and transformer ratings. This approach is

58 NER 5.12.2(c)(3).

based on high-level assessments of transmission hosting capacity previously conducted by ElectraNet and Powerlink. Details of these assessments are contained in Appendix F.

6.2.1 Technical limits

Network locations must be defined for each indicative hosting capacity value. We can leverage government-based REZ schemes by adopting the boundaries defined for governments' REZs. Locations, or "zones", must also be defined for the transmission network across the rest of the NEM, particularly those states without government-led REZ schemes. The ESB seeks stakeholders' feedback on how the areas of hosting capacity should be defined.

The ESB's preliminary view is that the ISP sub-regions developed by AEMO for its capacity outlook modelling should be used as the foundation for static hosting capacity assessments. These sub-regions are configured to identify major electrical subsystems within the electricity transmission network that allow free-flowing energy between transmission elements. The sub-regions used for the purpose of indicative hosting capacity assessments would evolve in line with AEMO's ISP modelling. Detail on AEMO's development of sub-regions is contained in Appendix F.

However, there is a trade-off when increasing the granularity of network "zones" given the limitations in modelling static assessments. Hosting capacity values will likely only reflect capacity in one location *or* in another location, and *not* as the cumulative hosting capacity when combined. Less granular network locations – e.g. adopting "zones" rather than values for each individual connection point – may be easier for an investor to understand the cumulative hosting capacity in a broader area of the network.

6.2.2 Economic assessment

Static modelling of transmission hosting capacity is extremely challenging. Available capacity is very dynamic, subject to real time network conditions, environmental conditions, generation dispatch across the meshed network as well as load levels, and the status of various network constraints. To take a static view of this dynamic concept therefore requires significant assumptions about grid usage patterns, meaning that any hosting capacity value can be indicative only.

Members of the Technical Working Group representing developers flagged that indicative hosting capacity values may, in fact, create challenges for investors and developers. They explained that, due to the limitations of the modelling, static hosting capacity modelling will produce outcomes that will be different to, and generally more conservative than, the outcomes of project-specific market modelling. This can create additional challenges in obtaining financing, as they have to explain the differences in modelling outcomes to financiers.

Measuring congestion in physical terms like hosting capacity will always have limitations. While more congestion is expected with the growth of renewable generation, that congestion may often occur at times when the value of energy is low. This then argues for a financial measure of congestion as being more valuable than physical measures. While financial measures would require price modelling, price modelling is necessary anyway to determine which generators reduce output as a new generator connects and enters the market. A focus on maximising value rather than physical access is also likely to be more consistent with the NEO and optimising the value of the transmission system.

The planning process could be enhanced to produce specified congestion metrics. These could include:

- Measuring the marginal value of congestion at potential connection points in the grid on the optimal development path. This is mathematically straightforward and would likely provide useful information, at least in terms of the relative attractiveness of connecting in different areas of the grid in different years. However, the marginal cost of an additional kW at each point on the grid does not reflect the congestion which might be experienced by a generator of a particular technology type or of a particular size.
- Measuring the cost of congestion on a 'standard' generator type and size calculated for a range of potential connection points. This would require more resources but provide information of more direct use but targeted to the defined standard connecting plant.

Alternatively the underlying data on which future congestion can be estimated could be made more readily accessible for investors to use as they see fit.

Rather than having TNSPs carry out periodic high-level assessments, in abstract, to provide indicative hosting capacity values, TNSPs could update a central database with information for investors (and their consultants) to undertake their own detailed market impact assessments for their specific project. The aim would be to improve the accessibility of the information that developers and investors need to conduct their power system modelling.

The ESB welcomes stakeholders' feedback on how best to resolve the limitations of determining hosting capacity values or on potential alternative approaches to enhancing information for investors.

These alternative approaches could be supported by a central portal for investors to access, in one place, all relevant information around the transmission network across jurisdictions. This would involve compiling information around constraints, transmission augmentation and transmission connections that TNSPs currently provide in their Transmission Annual Planning Reports (TAPRs) into to improve accessibility and comparison by investors.

There is also merit in exploring the extent to which underlying data could be made publicly available so that prospective investors (or their consultants) have enough network information to develop their own power flows and incorporate the results into their own model.

Members of the Technical Working Group suggested that separate curtailment figures would be useful for wind and solar. If an area of the network has capacity to support new generation, the TNSP should calculate the "wind head room" and "solar head room" to reflect how much (as a percentage of time) wind or solar generation, respectively, would be curtailed due to network constraints. Section 5.4 considers the alternate financial metrics of congestion in the network that could form the basis for calculating congestion fees.

Questions for stakeholders

Q24. Would investors find indicative network hosting capacity values useful for their siting decisions, noting the fundamental limitations of static modelling of the network?

Q25. If so, do stakeholders support defining "zones" of the network based on the sub-regions developed by AEMO for its capacity outlook modelling for the ISP? Are there alternative approaches the ESB should consider? Do stakeholders have feedback on how granular congestion zones need to be to provide useful information to investors?

Q26. Should the ESB focus its efforts on an alternative approach, including making underlying data accessible for investors to conduct their own modelling, more granular ISP modelling by the joint system planners or calculating curtailment forecasts? Are there further alternative approaches that the ESB should consider?

6.3 Treatment of diversity

Static modelling of hosting capacity requires assumptions to be made about grid usage patterns. This includes assumptions around the behaviour of generation and load across the entire network, as well as around broader network constraints. The following sections set out, for feedback, the ESB's preliminary views for the modelling assumptions if the option of assessing indicative hosting capacity values is pursued.

6.3.1 Generation

Appendix F details the generation dispatch assumptions that ElectraNet and Powerlink each adopted for their respective hosting capacity assessments:

- Powerlink assumed a single generation dispatch assumption, being a typical winter noon load and coincident output for the existing and committed scheduled and semi-scheduled generation projects.
- ElectraNet developed four modelling scenarios, each reflecting varying output profiles of different generation types. ElectraNet's assessment provided four values for each network location, to reflect the indicative hosting capacity under each system scenario.

The Technical Working Group provided feedback that the simplicity of Powerlink's approach is most useful for developers and investors to undertake a first screen of capacity in different locations. If multiple hosting capacity values are provided for each location, as with ElectraNet's approach, they would need to specify the probability of each scenario for investors to understand the potential extent of curtailed energy. A single dispatch assumption, resulting in a single hosting capacity value, may be easier for investors to use, as long as the assumptions for the assessment are made clear.

Alternatively, investors may prefer that the transmission hosting capacity values be presented on a technology-specific basis. For example, the indicative hosting capacity value could be presented as "X MW of wind hosting capacity, Y MW of solar hosting capacity and Z MW dispatchable".

Questions for stakeholders

Q27. Do stakeholders support hosting capacity assessments that provide investors with a single figure of static capacity under a single set of pre-determined operating circumstances? If so, do stakeholders have feedback on what the assumed operating circumstances for the assessment should capture?

Q28. If stakeholders prefer multiple hosting capacity values that reflect a range of scenarios, should seasonal conditions be relied on? Alternatively, Should the information be presented in terms of technology-specific values?

6.3.2 Load and storage

Just as we need to make assumptions around generation dispatch to assess hosting capacity, it will be necessary to determine the assumptions for load and storage under each scenario. Storage and load can uplift hosting capacity and support network security by drawing from the network and relieving congestion.

One option is that the static hosting capacity modelling uses assumptions that are consistent with the ISP inputs and assumptions (if relevant/appropriate) and that demand assumptions be consistent with the most recent NEM Electricity Statement of Opportunities (ESOO). The demand assumption should be made clear, for investors to understand in relying on the hosting capacity value.

We welcome the stakeholders' views on how best to determine how storage should be treated for hosting capacity assessments – specifically, what should be the assumed storage behaviour. Given the business models for grid scale batteries and pumped hydro are still evolving, and can be wide-ranging, the appropriate assumption is tricker to determine. A key question is whether grid scale batteries and pumped hydro should be treated differently. This may be appropriate given the operation of pumped hydro is reliant on rainfall.

In areas or periods of congestion, storage in different areas of the network will be incentivised to draw from the grid to alleviate constraints, depending on the operational access reform model that is implemented. This may also have broader implications for the other scenario assumptions. Whether storage is assumed to be generating or drawing from the network may need to depend on the zone in question and the likelihood of congestion in the area, as this will inform how a storage facility behaves. In areas of congestion, the modelling could assume all connected and committed storage in the network is generating at half capacity or that they are operating at full capacity.

The Technical Working Group also suggested that, alternatively, load and storage assumptions could be captured as operational constraints in the modelling.

Question for stakeholders

Q29. Do stakeholders have any feedback on how load and storage is best captured in the assessment of hosting capacity? Do stakeholders support assuming peak demand for the assessment?

6.3.3 Interconnector flows and types of constraints

There is a further question of how modelling of indicative hosting capacity at each connection point or in each zone should take into account the impact of broader network constraints, both intra-regional and inter-regional.

Appendix F details how ElectraNet and Powerlink captured network constraints for their respective hosting capacity assessments. Powerlink's assessment only captured constraints on the local network around the relevant connection point. ElectraNet's four system scenarios for its assessment also reflect a range of interconnector conditions. ElectraNet did not consider the potential impact of constraints in Victoria and New South Wales, or elsewhere in the NEM. As flagged above, Powerlink and ElectraNet's hosting capacity figures should be read as reflecting capacity in one location *or* in another location, and *not* as the cumulative hosting capacity when combined. This may dilute the usefulness of these values for investors' siting decisions.

For its capacity outlook modelling, AEMO has identified notional transfer limits between sub-regions represented at the time of 'Summer Peak', 'Summer Typical', and 'Winter Reference' in the importing sub-region. The detail of these notional transfer limits is contained in Table 25, Appendix F. The appendix also sets out how AEMO approaches identifying transfer limits for each seasonal condition. AEMO notes that it selects the most binding transfer limit. For example, if there is a transient stability issue which limits flow between sub-regions to a particular MW value, but that value is higher than the MW flow value for the voltage stability limit for that sub-region, then the voltage stability limit will be used to set the transfer capability.[59]

59 AEMO, ISP Methodology 2021, pp. 16-17.

Based on feedback from the Technical Working Group, the ESB is of the preliminary view that security constraints should be captured in the hosting capacity modelling, in addition to thermal constraints. While voltage constraints can often be alleviated with a relatively cheap solution by TNSPs/participants, this is not always the case and the resulting congestion may persist. We therefore consider it appropriate that the indicative hosting capacity also reflect voltage limitations. Technical Working Group members also noted the importance of determining assumptions around runback schemes to ensure greater than 50% of the network can be utilised. These members noted that without this assumption, project-specific modelling outcomes will be far more optimistic than the indicative hosting capacity value, which again can create hurdles for developers in seeking finance.

Questions for stakeholders

Q30. Should the hosting capacity assessment be based on all types of constraints, and not just thermal, even though this may result in more conservative figures?

Q31. Do stakeholders support relying on the notional transfer capabilities for interconnectors identified by AEMO through its ISP process?

6.4 Capacity included in the forecasts

6.4.1 Committed and existing projects only

At present, TNSP assessments of transmission hosting capacity typically capture:

- existing and committed transmission network arrangements, and
- existing and committed generation and load.

This is based on ElectraNet's assessment for its 2021 TAPR, which captured the impact of generation that is committed to connect to the South Australian transmission network, as well as the capacity expansion once Project EnergyConnect is commissioned.[60] Powerlink's analysis was also based on existing and committed transmission network arrangements, as well as recent generator commitments.[61]

6.4.2 Anticipated projects

Future network augmentations or expansions may alter the level of supportable generation at a given location. Whichever network congestion metric is adopted, for example indicative hosting capacity values, this could be overlayed with information about anticipated transmission projects. These should include ISP projects, as well as incremental upgrades/augmentations set out in TNSPs' TAPRs and Network Capability Incentive Parameter Action Plans (NCIPAPs). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets. This information should also reflect state-based transmission planning, such as the 2021 Infrastructure Investment Objectives Report,[62] which AEMO Services publishes in its capacity as the NSW Consumer Trustee under the Electricity Infrastructure Investment Act 2020 (NSW).

Information about the planned projects should be provided according to the location or zone that they each relate to, with details about the justification of the project and indicative timing. It will also be necessary to determine a standard measure for investors to understand the likelihood of the project

60 ElectraNet, 2021 Transmission Annual Planning Report, p. 52.

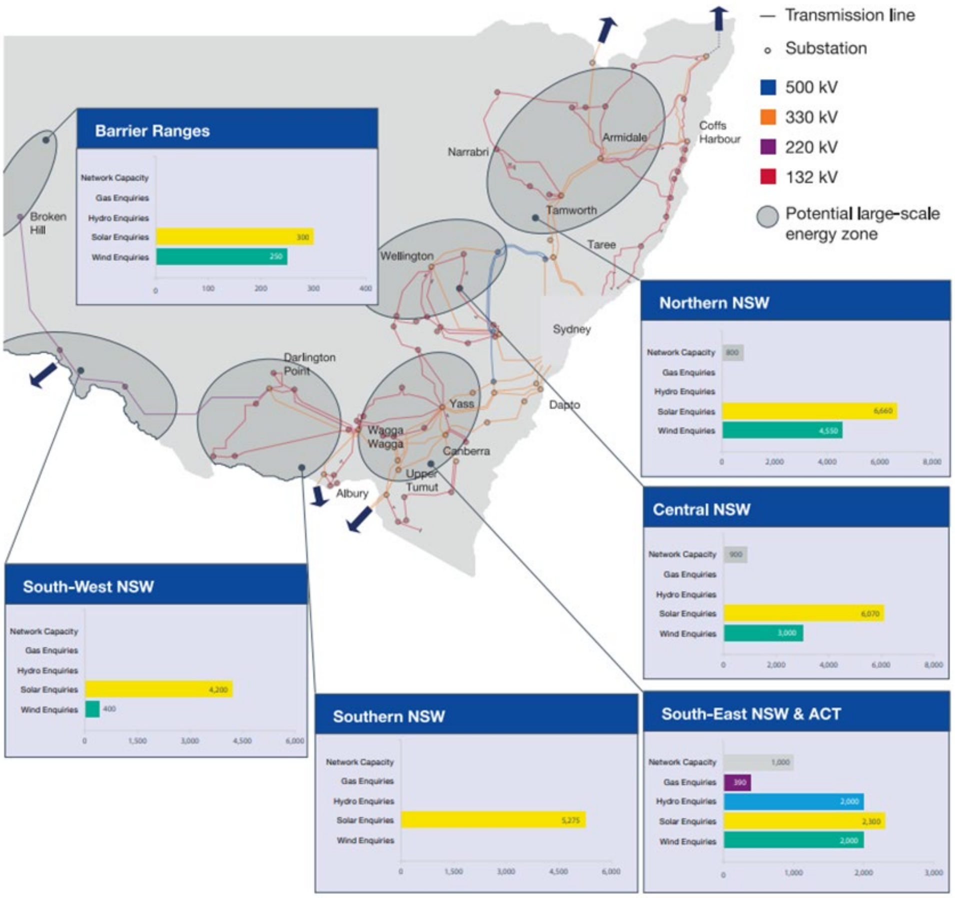
61 Powerlink, Generation Capacity Guide, August 2020, p. 5.

62 AEMO Services as Consumer Trustee, 2021 Infrastructure Investment Objectives Report, December 2021.

going ahead. For example, for the purposes of AEMO's ISP modelling, 'anticipated transmission projects' are 'transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon.'[63] The projects must be in the process of meeting *three of five* committed project criteria, including whether the proponent has obtained all required planning consents and/or whether necessary financing arrangements have been finalised.[64] Any network augmentation projects that do not meet three of the five above criteria could then be flagged as 'potential projects'.

The ESB is also of the preliminary view that investors should be provided with the cumulative capacity of generation for which connection enquiries have been received for a given location/zone. In its past TAPRs,[65] TransGrid provided information about the current generation connection enquiries it had received for specific locations in its network.

Figure 27 TransGrid assessment of current connection enquiries and available capacity



Source: Transgrid, New South Wales Transmission Annual Planning Report 2018, p. 54.

De-identified information about planned storage projects in a location should also be included in this information for investors.

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63 AEMO, Inputs Assumptions and Scenarios Report 2021, p. 126.

64 Refer to definition of committed projects from the AER's RIT-T instrument, as required by the AER's CBA Guidelines.

65 TransGrid's more recent TAPRs indicate it does not have any spare hosting capacity on its network.

Equally, investors should have visibility of planned generation withdrawal, including indicative timing. This information was provided in ElectraNet's 2021 TAPR.[66] In capturing such information for congestion zones, it will again be important that it is consistent with forecast generator closures in AEMO's ISP, to avoid conflicting information confusing potential investors.

We seek stakeholders' feedback on the below information, as well as any other information investors would value alongside indicative hosting capacity values.

6.4.3 Constraint information

The ESB is also of the preliminary view that whichever network congestion metric is adopted, such as indicative hosting capacity values, this should also be accompanied by both historical and forecast constraints corresponding to each network location/zone. This information can help investors (and stakeholders more broadly) understand how close the power flows in the network are to capacity limits or, vice versa, how much load (e.g. storage) is needed to alleviate congestion in a zone. The detail of the constraint information that TNSPs are required to collate under the NER is set out in Appendix F.

Questions for stakeholders

Q32. If indicative hosting capacity values are calculated, do stakeholders support capturing only committed network augmentations, generation and load or should anticipated projects also be included?

Q33. Do stakeholders support overlaying network congestion metrics with information about historical and forecast network constraints?

6.5 Form of information

It is important that indicative hosting capacity values for all locations/zones across the NEM, and overlayed information, are all contained in one place. This is to facilitate investors' ability to evaluate potential facility sites that span across different jurisdictions.

Several stakeholders, including the Clean Energy Council, have suggested that a central portal be adopted through which investors can access this information. The portal could be based on existing interactive mapping tools, such as AEMO's interactive map.[67] It could also expand on AEMO's existing Congestion Information Resource. In 2021, Powerlink introduced a geographical interactive mapping tool to complement the information contained in its TAPR templates. This provides perspective and context on potential network developments over the 10-year outlook period.[68] Similarly, Ausgrid has introduced its DTPAR Mapping Portal.[69]

It is envisaged that investors would be able to click on each zone to access the overlayed information discussed above, including forecast constraints and future transmission augmentations for that specific location.

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66 See section 6.2.

67 See https://www.aemo.com.au/aemo/apps/visualisations/map.html

68 See https://www.powerlink.com.au/reports/transmission-annual-planning-report-2021#resource-sections

69 See https://dtapr.ausgrid.com.au/

As is the case with Ausgrid's DTPAR, investors (and their consultants) accessing the portal should be able to download a system limitation templates/workbooks with the details of historical and forecast constraints, including the type of constraint, affected lines and the time that the constraints were binding.[70]

Questions for stakeholders

Q34. Do stakeholders support using existing interactive mapping tools as a basis for developing a NEM-wide central portal of information for investors?

6.6 Governance

A straightforward option is that AEMO would have responsibility for developing and administering the central information portal, building on its Congestion Information Resource. To support this function, there would also need to be an obligation on TNSPs to provide AEMO with relevant data with the relevant information provided by TNSPs for their respective networks. TNSPs are already obliged to provide data on generation connections to AEMO.[71] The ESB seeks views on what, if any, additional information is required. We also note that in the past, security concerns have presented an obstacle to the publication of detailed transmission system information and we seek views on how these issues can be managed in a way that still gives investors visibility of forecast congestion.

If the concept of indicative transmission hosting capacity values is progressed, Primary TNSPs could be responsible for assessing hosting capacity for their respective transmission networks. Each TNSP has the best understanding of the information around its own network needed for this assessment.

Section 5.9.1 contemplates AEMO having responsibility for preparing a congestion forecast methodology. TNSPs would apply this methodology that is prepared by AEMO and is consistent with the ISP inputs and assumptions, to ensure TNSPs are consistent in their approach to the assessments. Consistency is important to ensure investors have values across jurisdictions that can be properly compared.

Questions for stakeholders

Q35. Do stakeholders support the proposed governance arrangements?

Q36. What additional obligations are required to ensure that the right parties can access the right information, and how can security concerns be managed?

70 Ausgrid's DTPAR Mapping Portal allows systems limitation template to be downloaded.

71 See https://www.aemc.gov.au/rule-changes/transparency-new-projects

7 Next steps

The ESB invites comments from interested parties in response to this consultation paper by 21 December 2022. While stakeholders are invited to provide feedback on any issues raised in this paper, the key questions for consultation are summarised in Appendix B. Submissions will be published on the Energy Ministers' website, following a review for claims of confidentiality.

Submission information	
Submission close date	21 December 2022
Lodgement details	Email to: info@esb.org.au
Naming of submission document	[Company name] Response to transmission access reform directions Paper
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 5 December 2022, 2:30-4pm AEDT. 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 directions 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 March 2023. The next steps in the ESB's forward work program are set out below.

Milestone	Indicative timing
Public webinar on consultation paper	5 December 2022
Submissions due on consultation paper	21 December 2022
Draft recommendations for detailed design	March 2023
Submit proposed rules to Energy Ministers	June 2023

If Ministers adopt the ESB's recommendations, then 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. Glossary

Clamping	Clamping refers to AEMO's response to a situation when electricity is flowing from a high-priced region to a low-priced region (also known as a counter-price flow). Clamping reduces or stops the flow of electricity during these periods to reduce transmission charges for consumers.
Congestion	Electrical equipment being operated to its technical limit, meaning electricity cannot be dispatched to meet demand at the lowest possible cost.
Congestion fees	Upfront fees reflecting the present value of future costs of congestion created by the connection of a generator.
Constraint coefficient (coefficient)	Reflects the proportion of a generator's output or interconnector's flow which "uses" the equipment to which the constraint relates – it measures how much each generator contributes to each constraint.
Counter price flow	Counter-price flows is the name for the situation where electricity is flowing from a high-priced region to a low-priced region across an interconnector.
Congestion relief market	The congestion relief market (CRM) represents a component of the CRM design. It is a new market in addition to the energy market and ancillary services markets operated by AEMO. Participants submit CRM bids. The market is cleared and priced nodally i.e. participants are paid their locational marginal price for the cleared amounts.
Congestion relief market design	The CRM design refers to the overall design concept which includes the CRM and its integration with the existing markets (energy market and ancillary services).
Disorderly bidding	Refers to the situation when generators bid to the market floor price to maximise their individual dispatch quantities. In the presence of congestion, generators participating in constraints may bid to the market price floor in the knowledge that their bids are unlikely to impact the regional reference price. This bidding strategy arises because of the regional pricing regime in today's energy market.
Economic spill	Spill occurs when generation reduces output due to the market price.
Locational marginal price	The price representing the change in the cost of dispatch if an additional unit is supplied at that location.
Long run incremental cost	The long-run incremental cost is a method for calculating the value of a congestion fee. This method attempts to value the NPV of the increase in network expenditure required to provide a defined level of generator access with the new generator connected to the system.
Market price cap	A limit to how high the regional reference price can be in settlement. In the NEM, it is currently set at $15,500/MWh.
Market floor price	A limit to how low the regional reference price can be in settlement. In the NEM, it is currently set at $-1000/MWh.
Net present value	The difference between the present value of cash inflows and the present value of cash outflows over a period of time. It is a method for standardising costs and revenues over multiple periods of time for comparison at a single point in time.
Opportunity cost	The cost of the best foregone opportunity. I.e. the cost of a later opportunity that is no longer available due to a decision being made.

Priority access	Priority access gives preferential dispatch in the energy market. Participants gain access to the regional reference price depending on their prioritisation.
Queue position	The order in which generators receive priority access. A queue position of '0' has the highest priority. Subsequent queue numbers have lower levels of priority. Lower queue positions are allocated to incumbents and early joiners, higher queue positions are allocated to late joiners.
Regional reference node	The network node used for measurement of the regional reference price. Usually, this is a node located at the capital city of each region, with the exception of Tasmania, where the regional reference node is in the north of Tasmania where the Basslink interconnector connects to the island.
Regional reference price	The price representing the change in the cost of dispatch if an additional unit of load is supplied at the regional reference node.
Short run marginal cost	The cost of producing an extra unit of electricity.
Transmission curtailment	Curtailment happens when generation is constrained down or off due to operational limits.

Appendix B. Summary of consultation questions

Section	Questions	
3.3 Implementation considerations	Q1.	Should the core elements of the hybrid model be implemented on a staged basis and if so, what factors should inform the decision with respect to staging?
4.2.1 Parties subject to the arrangement	Q2.	Do you agree with the proposed scope of market participants included in this access reform?
	Q3.	Should different treatments apply to any particular categories of market participant?
4.2.2 Alternative distributions of congestion risk in the energy market		The ESB has proposed a decision option to round constraint coefficients in the energy market.
	Q4.	Do you agree with the assessment of risks and opportunities for these design options?
	Q5.	What is your preferred option and why?
4.2.3 Arbitrage opportunities between the energy market and CRM for out-of-merit generators	Q6.	Do you agree with the analysis of key risks and opportunities for each design option to respond to the new arbitrage opportunities between the energy market and the CRM?
	Q7.	Are the design choices more applicable to certain categories of market participant?
	Q8.	Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?
4.2.4 Treatment of storage acting as a generator and as a load	Q9.	Do you agree with the underlying assumptions for the respective incentives of storage acting as a generator and as load?
	Q10.	Do you agree with the analysis of key risks and opportunities for each design option?
	Q11.	Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?
4.2.5 Calculation of RRP	Q12.	Do you have a preferred calculation for RRP and why?
	Q13.	Which approach do you prefer for the treatment of FCAS and why?
	Q14.	If the technical implementation plan requires that we adopt your non-preferred calculation of RRP and FCAS prices, what are the risks?
4.6.6 Settlement of metered output	Q15.	Do you agree with the risks and benefits of the two options for the formula of settlements and their materiality?
	Q16.	Do you have a preferred settlement formula and why?
5.3.1 Form of queue right	Q17.	Should the ESB work towards providing as many unique queue numbers as is feasible (given implementation challenges) or is a tiered approach preferable?
5.3.2 Allocation mechanism	Q18.	What mechanism should be used to allocate queue positions to generators? E.g. first come first served, auctions, a combination or another approach?
5.3.3 Duration of rights	Q19.	Would stakeholders prefer that the priority access rights (i.e. queue positions) be set for: the life of the participant's asset, a fixed duration, or a fixed duration with a glide path?
	Q20.	If set for a fixed duration, what period of time do stakeholders consider would be most appropriate? Should this period be adjusted if combined with a glide path?

5.4.1 Method used to calculate fees	Q21.	Which of the proposed metrics do stakeholders consider should be used as the basis for calculating congestion fees? Are there alternative metrics the ESB should consider?
5.4.2 Fee calculation process	Q22.	Noting the trade-off between investor clarity and accuracy, do stakeholders have feedback on how bespoke the modelling should be?
5.6.2 Timing	Q23.	At what time within the connection process should the queue position or congestion fee be locked in?
5.6.3 Managing multiple simultaneous connection applications	Q24.	Should there be a process for batching connection applications and jointly establishing connection requirements and fees?
	Q25.	Could an expression of interest process, combined with auctions, be used to manage multiple simultaneous connections?
5.6.4 Qualifying criteria	Q26.	Should there be conditions precedent which must be met before a queue position or congestion fee is finalised and accepted? If so, what sort of measures would be appropriate?
5.6.5 Use it or lose it	Q27.	Once set, parties would be expected to progress to implementation. Should there be time limits or expiry dates for projects which do not progress in a timely manner? If so, what time limit would be appropriate?
5.7 Treatment of incumbents	Q28	Do stakeholders have a preference for any of the options listed regarding the treatment of incumbents in transitioning to the priority access variant? Are their alternative options for the treatment of incumbents under this model that the ESB should consider?
	Q29.	Do stakeholders support the calculation of congestion fees reflecting the protection of incumbents under the model? If so, do stakeholders have feedback on feedback on how to determine the appropriate degree of protection?
5.8 Options to reduce congestion impact	Q30.	Should the ESB develop proposals to give generators options to reduce their congestion impact (in return for a lower fee or worse queue position) as part of its congestion management reform package? If so, what options should be included?
5.9 Governance	Q31.	Do stakeholders support the proposed governance arrangements for providing locational signals?
6.2 Hosting capacity assessment	Q32.	Would investors find indicative network hosting capacity values useful for their siting decisions, noting the fundamental limitations of static modelling of the network?
	Q33.	If so, do stakeholders support defining “zones” of the network based on the sub-regions developed by AEMO for its capacity outlook modelling for the ISP? Are there alternative approaches the ESB should consider? Do stakeholders have feedback on how granular congestion zones need to be to provide useful information to investors?
	Q34.	Should the ESB focus its efforts on an alternative approach, including making underlying data accessible for investors to conduct their own modelling, more granular ISP modelling by the joint system planners or calculating curtailment forecasts? Are there further alternative approaches that the ESB should consider?
6.3 Treatment of diversity	Q35.	Do stakeholders support hosting capacity assessments that provide investors with a single figure of static capacity under a single set of pre-determined operating circumstances? If so, do stakeholders

		have feedback on what the assumed operating circumstances for the assessment should capture?
	Q36.	If stakeholders prefer multiple hosting capacity values that reflect a range of scenarios, should seasonal conditions be relied on? Alternatively, Should the information be presented in terms of technology-specific values?
	Q37.	Do stakeholders have any feedback on how load and storage is best captured in the assessment of hosting capacity? Do stakeholders support assuming peak demand for the assessment?
	Q38.	Should the hosting capacity assessment be based on all types of constraints, and not just thermal, even though this may result in more conservative figures?
	Q39.	Do stakeholders support relying on the notional transfer capabilities for interconnectors identified by AEMO through its ISP process?
6.4 Capacity included in the forecasts	Q40.	If indicative hosting capacity values are calculated, do stakeholders support capturing only committed network augmentations, generation and load or should anticipated projects also be included?
	Q41.	Do stakeholders support overlaying network congestion metrics with information about historical and forecast network constraints?
6.5 Form of information	Q42.	Do stakeholders support using existing interactive mapping tools as a basis for developing a NEM-wide central portal of information for investors?
6.6 Governance	Q43.	Do stakeholders support the proposed governance arrangements for the provision of enhanced information?
	Q44.	What additional obligations are required to ensure that the right parties can access the right information, and how can security concerns be managed?

Appendix C. Worked examples of the congestion relief market

A reference scenario has been created to illustrate the CRM design. It provides a simplified worked example of a looped network. Box 2 also includes simplified explanations of the RRP and calculations of LMP that are relevant to these examples.[72]

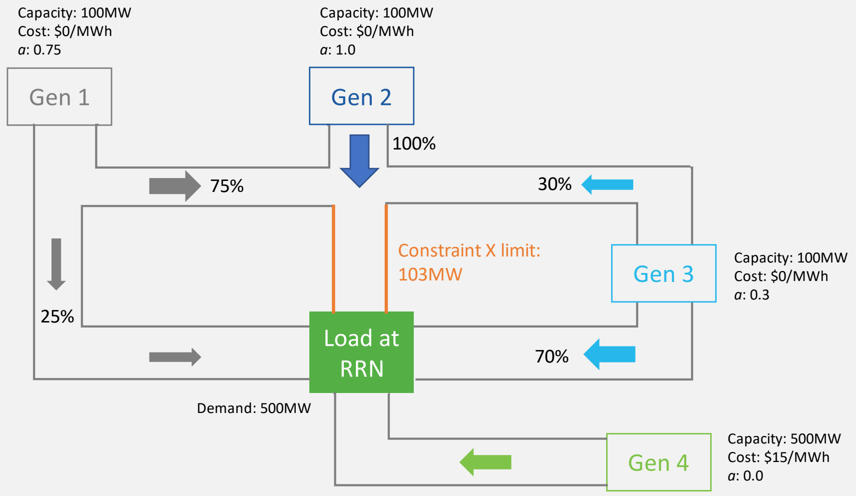
The reference scenario is modified to illustrate:

- benefits of storage and flexible load for relieving congestion
- design issues so that stakeholders can understand the choices proposed for consultation.

Box 2 Reference scenario applied to illustrate design choices

Reference scenario

The figure provides an illustrative example of a looped network with a flowgate constraint of 103MW.



Note: a = coefficient of a generator in the constraint
A flowgate is a transmission element by which electricity power flows. The constraint limit (or flowgate capacity) reflects the capacity of the associated transmission element or the transmission network more generally.

Gen 1, Gen 2 and Gen 3 are located behind the constraint. Gen 4 is unconstrained.

Gen 1, Gen 2 and Gen 3 are assumed to be variable renewable energy generators with short run marginal costs of $0/MWh. Gen 4 offers $15/MWh.

Regional reference price (RRP)

Gen 4 is a large generator at the node that supplies the balance of power. If the load increases by 1 MW from 500 MW to 501 MW, the additional cost to serve this load is $15/MWh from Gen 4.

Locational marginal pricing (LMP)

Gen 4 sets the LMP for the RRN based on its offer price, irrespective of bidding behaviour by generators behind the constraint. Gen 1, Gen 2 and Gen 3 each have their own LMP which does not affect the RRP.

The figure shows the impact of the coefficients on the LMP and dispatch outcomes. For example:

- Gen 1 has a coefficient of 0.75. For every 1MW flowing through the constraint, 0.33MW is dispatched around the constraint.
- Gen 2 has a coefficient of 1.0. For every 1MW flowing through the constraint, 0MW is dispatched around.
- Gen 3 has a coefficient of 0.3. For every 1MW flowing through the constraint, 2.33MW is dispatched around.

72 AEMO publishes LMPs using a methodology which determines the types of constraints that are relevant and their relative weighting (marginal cost) when more than one bind. Generators with lower coefficients will generally receive higher LMPs than generators with high coefficients in binding constraints.

Assume that the three generators bid at cost into NEMDE ($0/MWh). For simplicity, the calculations ignore MLFs.

With cost reflective bidding, the congestion price in the worked example is $20/MWh. Relaxing the constraint by 1MW would allow another 1.33 MW of generation from Gen 1 (cost $0/MWh) with a corresponding 1 MW reduction from Gen 4 (cost $15/MWh) at a cost saving of $20/MWh.

The table below shows the outcome of the LMP calculation.

LMP calculation for the generators

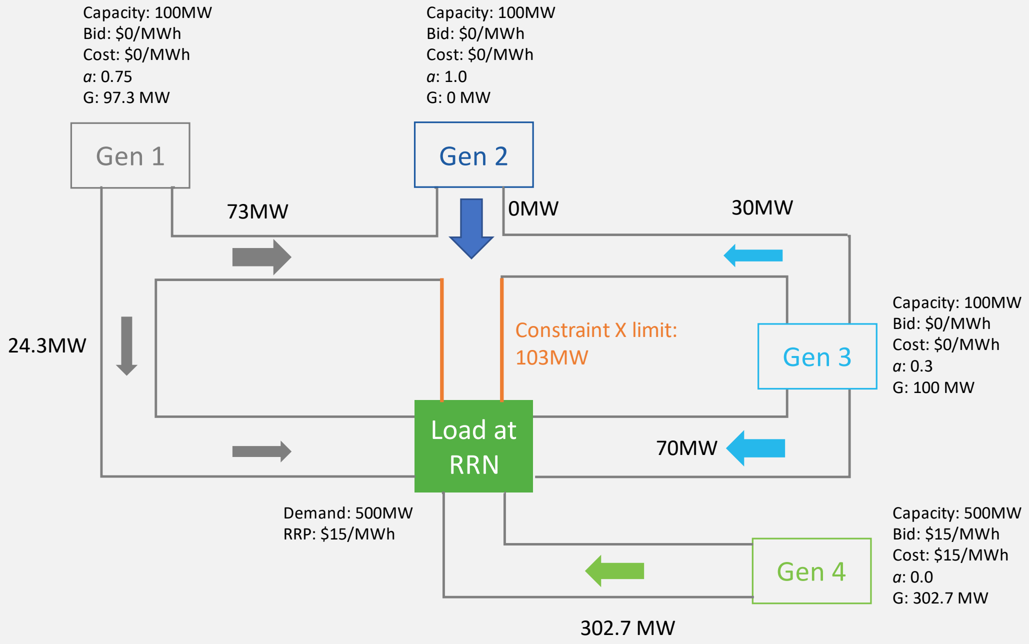
Unit	**Cost** $/MWh	**RRP** $/MWh	**a** coefficient	**Congestion price** $/MWh	**LMP** $/MWh RRP – a x CP
Gen 1*	0	15	0.75	20	0.00
Gen 2	0	15	1.0	20	-5.00
Gen 3	0	15	0.3	20	9.00
Gen 4	15	15	0.0	20	15.00

Note: *In this scenario, Gen 1 is the marginal generator. Congestion price = (RRP – LMP) / a = (15 –0) / 0.75 = 20

Dispatch outcomes depending on bids and LMPs

Comparison of LMP vs bid	**Dispatch outcome**	**Worked example**
LMP > bid	Full dispatch	Gen 3
LMP = bid	Partial dispatch	Gen 1 and Gen 4
LMP < bid	No dispatch	Gen 2

Dispatch outcomes based on cost reflective bidding



Note: G = dispatch MW

Gen 3 has the lowest coefficient. With *LMP > bid*, it is fully dispatched at 100MW of which 30MW flows through the constraint and 70MW around the constraint.

Gen 1 has the next lowest coefficient. With *LMP = bid*, it is partially dispatched at 97.3MW of which 73MW flows through the constraint and 24.3MW around the constraint.

Gen 2 has the highest coefficient. With *LMP < bid*, it is not dispatched.

Gen 4 supplies the balance of the load (302.7MW) to meet demand at the RRN. It is partially dispatched because its bid is equal to its LMP (also equal to the RRP because it is not contributing to the binding constraint).

Box 3 highlights the benefits of storage and flexible loads to relieve congestion. It provides a worked example where the reference scenario now includes a battery.

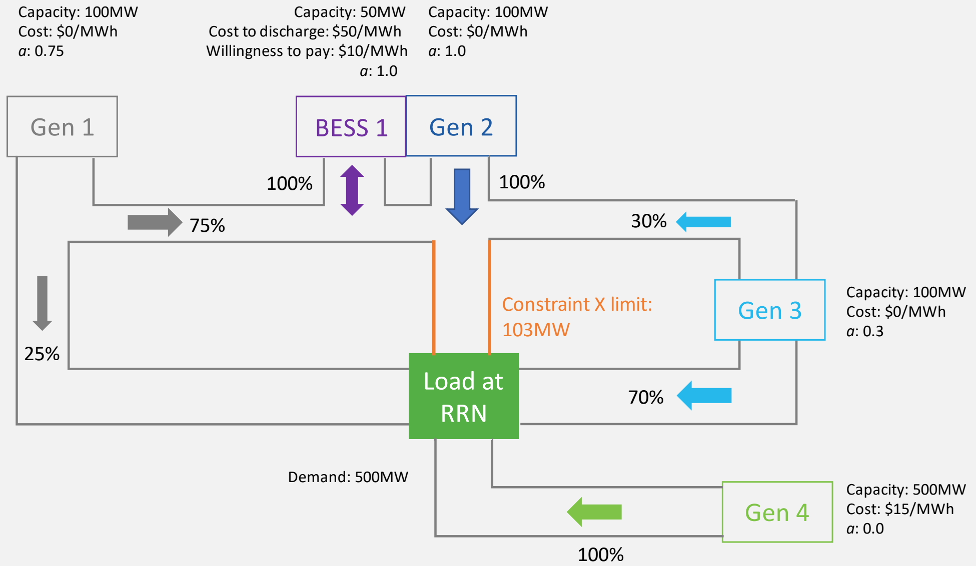
Box 3 Benefits of storage providing congestion relief

Reference scenario modified for storage

The reference scenario has been updated to include a storage plant:

- BESS 1 is located near Gen 2 with the same constraint coefficient 1.0
- BESS 1 has a cost of $50/MWh to discharge (opportunity cost based on its marginal value and cycling efficiency)
- BESS 1 is willing to pay $10/MWh to charge

Illustrative figure showing inclusion of storage behind a constraint



Assume all three in-merit constrained generators bid at the market floor price (-$1000/MWh) in the energy market to maximise their access to RRP. They bid cost reflectively in the CRM.

Assume BESS 1:

- has total capacity of 100MW but 50MW available capacity to charge and 50MW available capacity to discharge
- bids (as a generator) at cost in the energy market and the CRM[73]
- bids (as a load) as unavailable in the energy market and maximises its opportunity in the CRM.

The table below summarises their costs and bids.

Bids for the energy market and CRM

Unit	Cost *$/MWh*	Bid – energy market NEM *$/MWh*	Bid – CRM *$/MWh*
Gen 1	0	-1000	0
Gen 2	0	-1000	0
Gen 3	0	-1000	0
BESS 1 - charge	10	unavailable	10
BESS 2 - discharge	50	50	50
Gen 4	15	15	15

73 BESS 1 could take advantage of the arbitrage opportunities and bid at the market floor price in the energy market. This bidding strategy was discussed in sections 4.2.3 and 4.2.4. This example assumes that BESS 1 does not bid inconsistently between the two markets when it is out of merit.

Energy market

BESS1 charging could relieve the Constraint X by 1.0 MW for every MW dispatched.

But BESS 1 does not charge or discharge given the RRP of $15/MWh is higher than its willingness to pay $10/MWh and lower than its discharging bid of $50/MWh.

As a result:

- Gen 3 is fully dispatched at 100MW (coefficient 0.3)
- Gen 1 is partially dispatched at 97.3MW (coefficient 0.75)
- Gen 2 is curtailed (coefficient 1.0)
- BESS 1 does not charge or discharge (coefficient 1.0)

CRM

In the CRM, BESS 1 is still out of merit to discharge (as a generator) with a cost of $50/MWh. But BESS 1 is incentivised to charge (as a load) with an offer of $10/MWh compared to its LMP of $0/MWh.

As a result:

- Gen 1 has an incremental dispatch increase of 2.7MW (fully dispatched at 100MW), of which 2MW flows through the constraint and 0.7MW flows around the constraint
- Gen 2 has an incremental dispatch increase of 48MW (partially dispatched) which flows through the constraint
- BESS 1 fully charges at 50MW

The table below summaries the dispatch and financial outcomes.

Dispatch and financial outcomes with and without the CRM

Unit	Dispatch MW			Cost $			Profit $		
	Energy market G_{NEM}	*CRM deviations* G_{ADJ}	*Final dispatch* G_{CRM}	*Energy market*	*CRM*	*Total*	*Energy market*	*CRM*	*Total*
Gen 1	97.3	2.7	100	0	0	0	1,460	10	1,470
Gen 2	0	48.0	48	0	0	0	0	0	0
Gen 3	100	0.0	100	0	0	0	1,500	0	1,500
BESS - load	0	-50.0	-50	0	-500	-500	0	500	500
Gen 4	302.7	-0.7	302	4,541	-10	4,530	0	0	0
Total	**500**	**500**	**4,541**	**4,541**	**-510**	**4,030**	**2,960**	**510**	**3,470**

Total costs decrease as a result of the CRM because:

- congestion relief from the BESS allows an additional 0.7MW from Gen 1 ($0/MWh) to flow around the constraint and displace the higher cost Gen 4 (cost of $15/MWh)
- BESS 1 negative costs relate to the economic value of its willingness to pay at $10/MWh.

Total profits increase as a result of the CRM because:

- Gen 1 is dispatched at its LMP of $3.75/MWh
- Gen 2 is dispatched at its LMP of $0/MWh
- BESS is charged at its LMP of $0/MWh. Its profits represent the economic gain between its cost to charge ($10/MWh) and its LMP ($0/MWh).

This scenario is highly simplified. There are only three participants affected by the CRM adjustments, of which one is the marginal generator in the CRM (Gen 2). As a result, Gen 2 shows nil profit gain from the CRM but it has significantly mitigated its curtailment risk and was dispatched at 48MW.

The worked example illustrates how the CRM creates incentives for storage and scheduled load to help to alleviate congestion. This addresses the transmission access reform objective to achieve efficient market outcomes in dispatch, but it also creates efficient market outcomes in investment. It provides a signal to storage and flexible load to locate in areas of congestion in order to maximise the opportunities of profit arbitrage.

Section 4.2.2 introduces an alternative re-distribution of congestion risk by rounding coefficients in the energy market. Box 4 provides a worked example.

Box 4 Worked example of rounding constraint coefficients

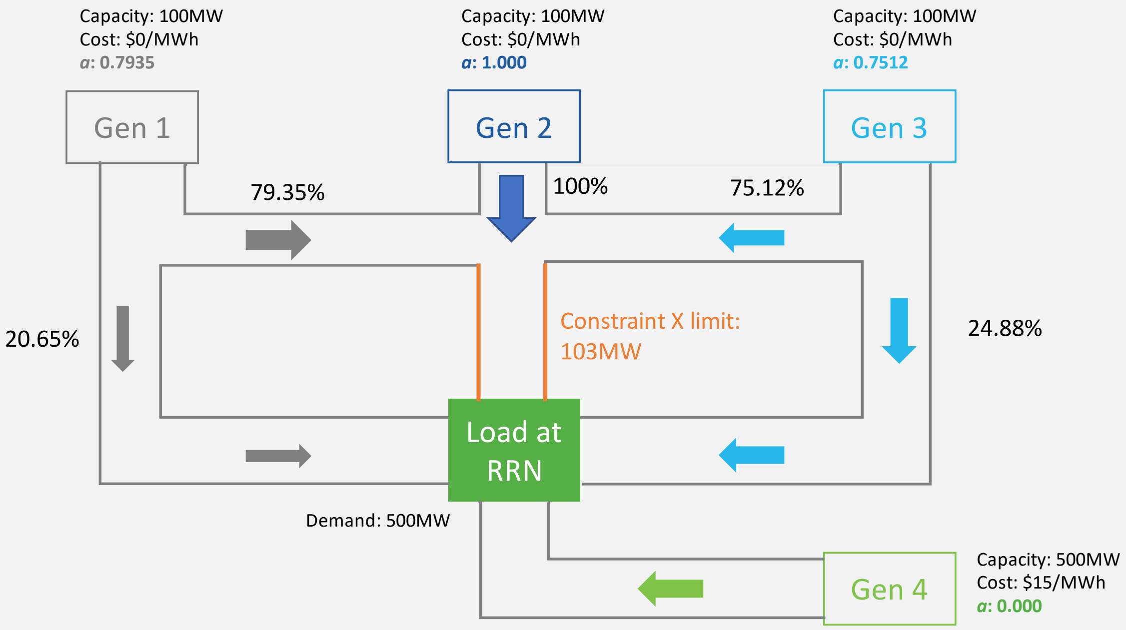
Reference scenario modified for constraint coefficients

In circumstances where competing generators all offer the same price (for instance, when generators have bid the market floor price), NEMDE minimises the cost of congestion by dispatching generators with the lowest coefficients first even if the difference in coefficients is very small. This feature of dispatching tied bids based on generator coefficients gives rise to "winner takes all" outcomes when a single network constraint is affecting the dispatch of generators. To illustrate this issue , the coefficients of Gen 1 and Gen 3 in the reference scenario are modified as follows:

- Gen 1 = 0.7935
- Gen 3 = 0.7512

The coefficients for Gen 2 (1.0000) and Gen 4 (0.0000) remain unchanged.

Illustrative figure showing modified constraint coefficients



Note: a = coefficient of a generator in the constraint

For the purpose of this worked example, assume that coefficients are rounded to 1 decimal place.

Coefficients with and without rounding

Unit	Coefficient (no rounding)	Coefficient (rounding 1 decimal place)
Gen 1	0.7935	0.8
Gen 2	1.0000	1.0
Gen 3	0.7512	0.8
Gen 4	0.0000	0.0

Energy market and CRM, with and without rounding coefficients

As before, assume all three constrained generators bid at the market floor price (-$1000/MWh) in the energy market to maximise their access to RRP. They bid cost reflectively in the CRM. The table below summarises their costs and bids.

Generator bids for the energy market and CRM

Unit	Cost *$/MWh*	Bid – energy market NEM *$/MWh*	Bid – CRM *$/MWh*
Gen 1	0	-1000	0
Gen 2	0	-1000	0
Gen 3	0	-1000	0
Gen 4	15	15	15

In the energy market, NEMDE prioritises the bids based on a combination of MLF-adjusted energy market bids and constraint coefficients. In the case of our worked example with tied bids, the impact of the coefficients can be easily identified.

Energy market without rounding

Given the bids are at the market price floor, NEMDE dispatches from lowest to higher coefficient:

- Gen 3 is fully allocated access of 100MW (coefficient 0.7512)
- Gen 1 is partially allocated access of 35.1MW (coefficient 0.7935)
- Gen 2 is not allocated access (coefficient 1.000).

Energy market with rounding

NEMDE dispatches from lowest to higher coefficient with rounding applied:

- Gen 3 is partially allocated access of 64.4MW (coefficient 0.8)
- Gen 1 is partially allocated access of 64.4MW (coefficient 0.8)
- Gen 2 is not allocated access (coefficient 1.0).

Gen 3 and 1 have tied bids. Their blocks of energy are dispatched in proportion to the MW sizes of the respective bands.[74]

CRM with or without rounding

In the CRM, the physical dispatch would be based on a combination of MLF-adjusted CRM bids and constraint coefficients without rounding. In this simplified scenario where the bids are tied in both the energy market (at the market floor price) and CRM (at cost of $0/MWh), the physical dispatch is equivalent to the energy market outcomes without rounding:

- Gen 3 is fully physically dispatched at 100MW (coefficient 0.7512)
- Gen 1 is partially dispatched at 35.1MW (coefficient 0.7935)
- Gen 2 is not dispatched (coefficient 1.0000).

The table below summaries the dispatch and financial outcomes.

Dispatch and financial outcomes of energy market and CRM, with and without rounding coefficients

Unit	Total cost $		Energy market profit $		CRM profit $		Total profit $	
Option	*Without rounding*	*With rounding*	*Without rounding*	*With rounding*	*Without rounding*	*With rounding*	*Without rounding*	*With rounding*
Gen 1	0	0	527	966	0	0	527	966
Gen 2	0	0	0	0	0	0	0	0
Gen 3	0	0	1,500	966	0	96	1,500	1,062
Gen 4	5,473	5,473	0	0	0	0	0	0
Total	**5,473**	**5,473**	**2,027**	**1,931**	**0**	**96**	**2,027**	**2,027**

Without rounding, Gen 3 has a more favourable coefficient and is granted full access to the RRP. The congestion risk is borne by Gen 1 in the form of reduced access and profits.

With rounding, Gen 1 and Gen 3 have the same coefficient and share the congestion risk i.e. shared access to the RRP. Profits are more evenly distributed between the generators behind the constraint.

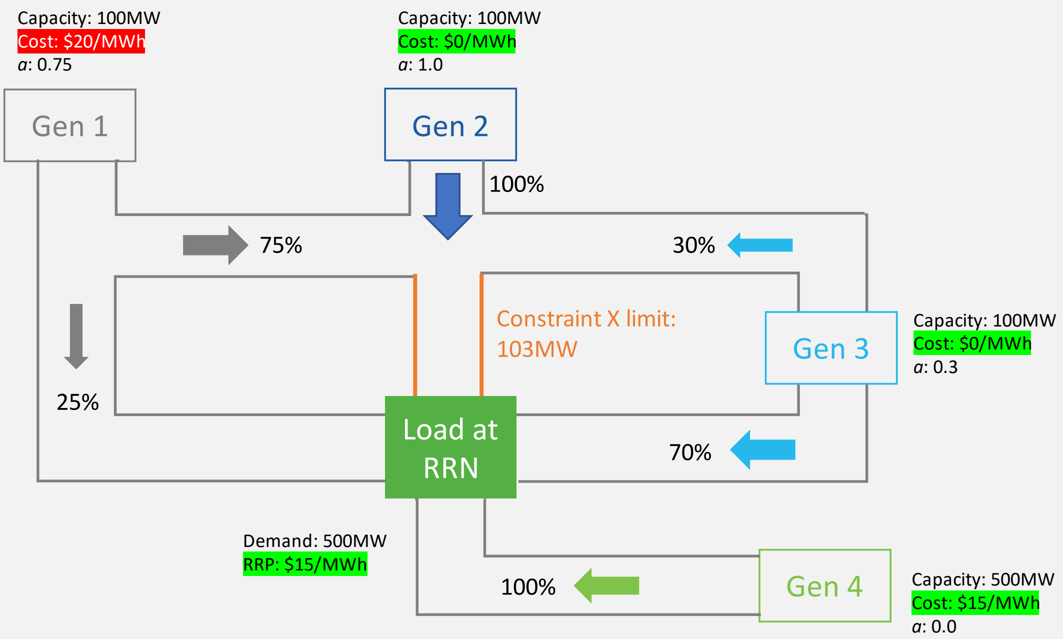
In this simplified scenario, Gen 2 is curtailed with or without the rounding.

Section 4.2.3 identifies the arbitrage opportunities between the energy market and the CRM. The reference scenario is updated below to illustrate the out-of-merit issue as it applies to generators.

Box 5 Worked example of the out-of-merit issue

Reference scenario modified for Gen 1 costs ($20/MWh)

Updated from the reference scenario, Gen 1 has costs of $20/MWh (previously $0/MWh).



Note: a = coefficient of a generator in the constraint

Gen 4 offers $15/MWh. As a large generator at the node, this ties the RRP to its offer price, irrespective of bidding behaviour by generators behind the constraint.

Gen 1 has costs of $20/MWh and is out-of-merit. Gen 2 and Gen 3 are in merit.

NEMDE will dispatch based on a combination of bid price and constraint coefficients.

Status quo

Under the status quo, Gen 1 is out-of-merit and will not bid to be dispatched. Gen 2 and Gen 3 are constrained with *costs < RRP*, they will bid to the market price floor of -$1000/MWh to maximise their access and physical dispatch.

Generator bids for the status quo energy market

Unit	Cost *$/MWh*	Bid – energy market NEM *$/MWh*
Gen 1	20	20
Gen 2	0	-1000
Gen 3	0	-1000
Gen 4	15	15

The table below shows that Gen 1 incurs no costs and receives no revenue. Gen 2 is partially dispatched at 73MW. Gen 3 is fully dispatched at 100MW. Gen 2 and Gen 3 have revenue and profits of $1,095 and $1,500 respectively.

74 Refer to AEMO Schedule of Constraint Violation Penalty Factors, November 2017, p.24 https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/schedule-of-constraint-violation-penalty-factors.pdf

Dispatch and financial outcomes of status quo market

Unit	G_{NEM} *MW*	Revenue = G_{NEM} x RRP $	Cost $	Profit $
Gen 1	0	0	0	0
Gen 2	73	1,095	0	1,095
Gen 3	100	1,500	0	1,500
Gen 4	327	4,905	4,905	0
Total	**500**	**7,500**	**4,905**	**2,595**

Energy market and CRM

All three constrained generators bid at the market floor price (-$1000/MWh) in the energy market to maximise their access to RRP. They bid cost reflectively in the CRM. The table below summarises their costs and bids.

Generator bids for the energy market and CRM

Unit	Cost *$/MWh*	Bid – energy market NEM *$/MWh*	Bid – CRM *$/MWh*
Gen 1	20	-1000	20
Gen 2	0	-1000	0
Gen 3	0	-1000	0
Gen 4	15	15	15

Allowing out of merit generators to access the RRP

In the energy market (NEM), the constrained generators have tied bids at the market price floor. NEMDE differentiates the bids based on constraint coefficients. Gen 1 has a more favourable coefficient than Gen 2 (0.75 compared to 1.0). Gen 1 is allocated access (G_{NEM} = 97MW). Gen 1 does not incur any costs of generation until the CRM physical dispatch is finalised. Gen 2 does not receive any access to RRP.

In the CRM, Gen 1's true costs of $20/MWh are factored into the CRM and is not physically dispatched (G_{CRM} = 0MW). Gen 2 has costs of $0/MWh and is physically dispatched. Gen 4 makes up the remaining balance of the load at the RRN.

Allowing out-of-merit generators to access the RRP will transfer profits from Gen 2 (in-merit) to Gen 1 (out-of-merit). Access to the RRP for in-merit generators would be diluted compared to today's energy market.

Excluding out of merit generators from accessing the RRP

Excluding out of merit generators from receiving payments in the energy market would maintain wealth transfers as they currently stand.

In the worked example, if Gen 1's bid was excluded from the energy market as being out-of-merit, it would not receive access to the RRP (G_{NEM} = 0). Profits of $1,095 would be retained by Gen 2.

Dispatch and financial outcomes including and excluding out-of-merit from receiving access to the RRP

Unit	G_{NEM} MW		G_{CRM} MW		Cost $		Profit $	
Option	*Including out of merit*	*Excluding out of merit*	*Including out of merit*	*Excluding out of merit*	*Including out of merit*	*Excluding out of merit*	*Including out of merit*	*Excluding out of merit*
Gen 1	97.3	0	0	0	0	0	1095	0
Gen 2	0	73	73	73	0	0	0	1,095
Gen 3	100	100	100	100	0	0	1500	1,500
Gen 4	302.7	327	327	327	4905	4905	0	0
Total	**500**	**500**	**500**	**500**	**4,905**	**4,905**	**2,595**	**2,595**

Appendix D. Access to the regional reference price and contracting

Objectives for market participants

The principal objectives for market participants for contracting are to:

- provide generators and energy storage systems with reasonably certain revenue streams when combined with their spot market revenues
- provide new generation and energy storage investments with reasonably certain revenue streams and incentives to actively participate in the NEM
- provide VRE generation with contracts that can firm their revenue streams or complement their outputs
- provide retailers and wholesale customers that are participating in the NEM with reasonably certain cost streams when combined with their spot market costs.

Considerations for transmission access reform

A key consideration for the transmission access reform is to ensure that the design choices do not undermine contract liquidity and the ability of retailers to get contracts that match their needs. In turn, this means recognising that:

- Since customers will pay for their energy consumption at the RRP, most retailers and wholesale customers will want hedge contracts that are referenced against the RRP and not the LMP.
- Most contracts required by retailers to effectively hedge their customers' loads will be provided by generators with dispatchable generation and/or storage plant.
- Contract markets explicitly drive mass market retail prices through the New South Wales, South Australia and southeast Queensland Default Market Offer (DMO) and the Victorian Default Offer (VDO).

Given that one of the major cost components for retailers in providing electricity to consumers is the cost of contracts that are used to hedge their loads,[75] the design of the proposed access regime should address how it:

- affects the availability and price of contracts which enable a range of retailers to efficiently hedge their customer's loads and
- facilitates competition between retailers.

If generators are unsure about their access to RRP they may be less willing to sell contracts linked to RRP and this could reduce liquidity and increase wholesale prices. The large gentailers have some ability to internalise the contracting between generators and retailers but they will still require access to the RRP for their own generation to hedge their retail loads. Smaller retailers (without large generation portfolios) are particularly reliant on contract arrangements for hedging purposes.

The design choices in chapter 4 consider how generators can continue to sell contracts linked to RRP and ensure they can manage those contract risks with physical generation. The opt-out principle in the CRM provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements.

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75 Australian Energy Council, 'Background on Factors Behind Retail Electricity Prices, DMO/VDO', May 2022

Contract types

Some of the common types of contracts traded in the NEM include:

Name	Description	Key risks
Caps	The buyer pays a premium and receives the difference between the spot price and an agreed strike price when the spot price exceeds the strike price. Strike prices are typically \$300/MWh, \$500/MWh or \$1000/MWh.	The seller needs access to the RRP when the spot price exceeds the strike price. E.g. a hydro plant would want to dispatch when the spot price exceeds the strike price in order to generate revenues in the spot market that offset its payments to the cap buyer.
Asian options	Also called average rate options. The contract is settled using the average spot price over an agreed averaging period.	The contract party needs to manage its access to the RRP on an ongoing basis. The average price volatility will be less than spot price volatility. Short periods of curtailment can be managed within a portfolio of generation assets. Extended periods of curtailment, particularly when RRP is high, can be more challenging.
Swaps	Two way contract for difference whereby both parties swap the floating spot price for an agreed fixed price. There are different periods to which the swap can apply e.g. peak, super peak, off peak, load following. A load-following swap trades at a premium to standard swaps and are used by retailers to lock in the hedge cost of their retail load over a wide range of metered outcomes. They may also include elements of profit or netback sharing.	The main risks for generators selling swap contracts are high average prices for the periods for which the swap contract applies. High average prices can often be substantially affected by some very high prices or a general shift in prices due to shift in fuel prices. To manage these price risks, the swap seller needs to manage its access to the RRP on an ongoing basis. For a generator that sells a load following swap contract it needs to ensure that it has access to the RRP at times when the prices are not low for quantities that are greater than or equal to the uncertain amounts in the load following contract.
ASX futures	Standardized exchange traded versions of common derivatives and liquidity is supported by voluntary market making arrangements. The ASX trades: • Base Load Futures • Peak Load Futures • \$300 Cap Futures and • Base Load Strip Options The \$300 Cap Futures are for a quarter's duration and the base load strip options are four quarters of \$300 Cap Futures bundled together. The benefit of futures is their liquidity, anonymity and price transparency but they do come with additional requirements for margining which requires adequate funding arrangements.	Management of the risks of selling base and peak load futures is very similar to selling the equivalent swap contracts, which in turn requires access to the RRP. Management of the risks of selling \$300 Cap Futures is very similar to selling the equivalent \$300 cap contracts, which in turn requires access to the RRP at time when prices exceed \$300/MWh.

This is not an exhaustive list but gives an indication of the range and congestion risks that the counterparties to contracts with retailers need to manage as part of their contracting arrangements.

New contract arrangements are developing in response to changing business models and market opportunities.

For example, a virtual storage contract[76] provides the buyer with the equivalent financial position of owning storage e.g. a collar arrangement with the floor settling based on the *m* lowest prices each day and the cap on the *n* highest prices each day.

Box 6 indicates how contract arrangements for PPAs might respond to sharing in the profit gains of the CRM.

Box 6 Opportunities in the CRM for purchase power agreements (PPAs)

Long term contracts are a critical part of the investment ecosystem for generation and storage assets. They provide revenue surety for equity and debt financiers. VRE assets have typically secured a PPA as part of reaching financial close and securing more favourable financing terms.

Historically, PPAs comprised a whole of meter swap that allowed a VRE generator to lock in the price for their entire output over many years. PPAs have evolved to limit the buyer's exposure to negative prices and marginal loss factors and may have various arrangements for the supply of LGCs.

Parties to a PPA could choose to opt out of the CRM and maintain the contract terms with reference to the energy market. However, the CRM provides an opportunity for profit gains and parties will be interested to adjust their contract terms to take shared advantage of this upside.

For the purpose of this explanation, the variables are defined as follows:

$G_{metered}$	metered output of a unit
G_{NEM}	dispatch output of a unit from the energy market
LMP	locational marginal price from the CRM
RRP	regional reference price
P_C	contract price (strike price)
P_{LGC}	large scale generation certificate price
Q	contract quantity

There are currently three key contract arrangements for PPAs:

Contract arrangements	Generator revenue
Financial contract (swap contract) with a separate payment for LGCs	$= G_{metered} \times RRP + Q \times (P_C - RRP) + G_{metered} \times P_{LGC}$
Physical PPA including payment for LGCs	$= G_{metered} \times P_C$
Physical PPA excluding payment for LGCs	$= G_{metered} \times P_C + G_{metered} \times P_{LGC}$

The current PPAs refer to $G_{metered}$ as one of the contract terms i.e. quantity of generation.

If the PPA quantities are determined from the access quantities (G_{NEM}) rather than the metered quantities ($G_{metreed}$), it would allow alternative contract arrangements for parties to share the benefits of the CRM and simplify the bidding in the CRM.

Assume that the parties have entered into a physical PPA including payment for LGCs.

PPA payments $= G_{NEM} \times P_C$ + CRM profits

CRM profits $= (G_{metered} - G_{NEM}) \times (P_{LGC} + LMP)$

Under this arrangement:

If $(P_{LGC} + LMP) > 0$, then the VRE generator should increase its output above G_{NEM}

[76] Renewable Energy Hub, Lessons Learned Report #2, July 2020, https://arena.gov.au/assets/2020/09/renewable-energy-hub-lessons-learned-report-2.pdf

If (P_{LGC} + LMP) < 0, then the VRE generator should decrease its output below G_{NEM}.

It can achieve both of these outcomes by using an offer (bid) price of $-P_{LGC}$ which is its opportunity costs of not generating.

If future PPAs used the access quantity as the basis for the contract quantity then it would be relatively easy to bid such plant into the CRM and it would also open up potential benefit sharing of participating in the CRM with the PPA counterparties.

Another PPA alternative is for the reference price for the whole of meter swap contract is for this contract to be references to the LMP rather than the RRP. This would be a suitable arrangement for contracts between VRE and storage facilities

Retailers without their own generation portfolios

Retailers without their own generation portfolios are generally interested in having access to:

- swap contracts with predetermined quantities: flat, peak, off peak, sculpted, super peak, PV profile
- swap contracts with quantities determined from other variables or measurements such as temperature, retail load (load following) etc.
- cap contracts
- futures.

Other than a fixed PV profile most standalone VRE generation will not be able to provide the sort of contracts retailers will want. Retailers will still contract with VRE generation to satisfy any of their renewable energy requirements for LGCs etc. but will have to focus on contracting with dispatchable generation to manage their load risks and satisfy their retailer reliability obligations.

For retailers without their own generation portfolio, the counterparties to the contracts they require will most likely be market generators with dispatchable generation and storage plant.

Conclusion

In today's energy market, congestion risk is borne by generators and the costs are ultimately passed to consumers in the form of risk premiums for contracts and/or retail prices. Congestion risks can be challenging to manage given the unpredictability of dispatch outcomes and the uncertainties of new incoming generation projects.

The hybrid model proposes two key variants to manage this congestion risk (with priority access or via a congestion fee). Within this model, there are a number of design choices to refine this ability to redistribute congestion risk and reduce revenue volatility.

The CRM design choices recognise the importance of access to the RRP to manage contracts. The following list outlines some of these possible design options:

- Rounding of constraint coefficients is intended to buffer revenue volatility and reduce spot price exposure risks for contracting parties.
- The exclusion of out-of-merit generators from the energy market is intended to reduce unproductive wealth transfers and allow in-merit participants to continue managing their contract positions, as expected today.
- The different design choices for storage recognise the different requirements for access to the RRP when acting as a generator versus acting as load. Storage will represent a larger component of the dispatchable generation mix in the future energy system and will play a significant role in the liquidity and pricing of contract markets.
- The calculation of RRP and the calculation of settlements (metered output) recognise the key reference terms for contracts.

The CRM design allows for additional efficiency gains to be shared as profits between the CRM participants. The worked example demonstrates that for financial and physical PPAs, the CRM design (with or without priority access) can result in better or equivalent financial outcomes to the current energy market dispatch. It is expected that some contracts will be modified to allow contracting parties to share in the profit gains from the CRM.

Where this cannot be achieved, the opt out principle provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements.

Appendix E. Congestion management model

Overview

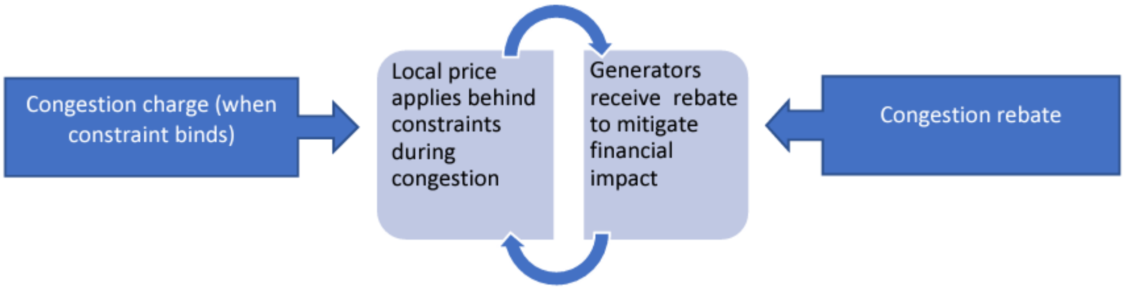
The ESB considers the CRM will be the primary model for consideration in operational timeframes. In the case that the implementation costs are too high or other challenges arise with the CRM, the ESB will continue to develop the CMM in the background as a second choice.

This appendix provides background detail to the proposed CMM design including a key choice regarding the method for allocating congestion rebates. It highlights the similarities in algebraic formulation between the CMM and CRM that achieves the transmission access objective of dispatch efficiency. It also notes the key differences between the CMM and CRM.

Overview

The CMM is designed to retain the existing NEMDE optimisation algorithm but applies changes to settlement to address congestion management by affecting bidding incentives at the margin.

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.



Source: ESB

When constraints are binding, the CMM introduces a dual mechanism of a congestion charge and a congestion rebate.

CMM$ = G x RRP – congestion charge + congestion rebate

Where:

CMM$ energy settlement under the CMM

G dispatch MW

RRP regional reference price

The congestion rebate is funded from the settlement residue which arises due to the CMM congestion charge across all dispatched generators. The congestion charge is equal to the difference between the RRP and a generator's LMP. The congestion rebate would distribute the residue amongst the eligible parties. A key component of this model design relates to the choice of rebate allocation method.[77]

77 ESB, https://esb-post2025-market-design.aemc.gov.au/transmission-and-access consultation paper, May 2022

Congestion charge

The CMM encourages more efficient dispatch by exposing generators to a congestion charge during operational timeframes. The congestion charge is equal the quantity of energy dispatched multiplied by the difference between RRP and LMP = G x (RRP – LMP). A generator is effectively settled at its LMP for energy dispatched.

The congestion charge in the CMM encourages a generator to bid at its short run marginal cost (SRMC), thereby aligning the incentives of generators with an overall least-cost dispatch. With cost-reflective bidding and LMP settlement, generators are only dispatched if their LMP is no lower than their cost.

Congestion rebate

A key element of the CMM is the congestion rebate. It is intended to make market participants, in aggregate, indifferent to the introduction of the congestion charge. There are different ways in which the settlement residue can be allocated as the rebate.

Under current arrangements, the congestion rebate is proportioned on the basis of the volume of actual generation dispatched. This leads participants to bid to maximise dispatch rather than disclose their costs. Allocating rebates on other metrics will change those incentives.

To encourage cost-reflective bidding and hence efficient dispatch, generators need to be exposed on the margin to their LMP i.e. each extra MW is paid LMP.

This could be achieved by paying generators *LMP x dispatch quantity (G)* in settlement. However, because LMP is often less than RRP, this leaves generators receiving less, in aggregate, than they do today. It also leaves a residue in settlement because non-scheduled load continues to pay the RRP in settlement.

To address both issues, the residue could be paid out to generators. However, to ensure that generators continue to be paid LMP at the margin, the residue shares must be independent of dispatch output. This is the conceptual basis (and challenge) for the CMM to define residue shares which are independent of generator output, otherwise bidding behaviours may be distorted as in status quo arrangements.

Rebate allocation methods

The original CMM proposal in the ESB post-2025 options paper published in March 2021 proposed a pro-rata access allocation metric whereby a generator would receive a proportion of the settlement residue equal to their proportion of total availability participating in the constraint. The ESB has considered the pro-rata access method and three alternative rebate allocation methods.

The allocation methods vary the net financial outcomes by affecting the congestion rebate. Four potential allocation methods include:

- Pro-rata access based on offered availability[78]
- Pro-rata entitlements based on a combination of constraint coefficients and offered availability
- Winner-takes-all based on constraint coefficients
- Inferred economic dispatch based on a combination of constraint coefficients and inferred costs.

[78] Refer to ESB post 2025 consultation paper, March 2021

Details of these allocation methods are provided in an ESB working paper: Working paper_CMM allocation methods.[79]

Similarities and differences between the CMM and CRM

The CMM and CRM share the same algebraic formulation.

CRM formulation

CRM\$	$= G_{NEM} \times RRP + (G_{CRM} – G_{NEM}) \times LMP$

Where:

CRM\$	energy payment to generator (\$)
G_{NEM}	dispatch from the energy market (MWh)
G_{CRM}	final physical dispatch including CRM adjustments (MWh)
G_{ADJ}	CRM adjustments = $G_{CRM} – G_{NEM}$ (MWh)

If the following terms are applied, its similarity to the CMM is more visible.

CRM\$	$= A \times RRP + (G – A) \times LMP$

Where:

CRM\$	energy payment to generator (\$)
A	access to RRP dispatch from the energy market (MWh) = G_{NEM}
G	final physical dispatch including CRM adjustments (MWh) = G_{CRM}

CMM formulation

CMM also determines an access quantity and uses the same settlement formula:

CMM\$	$= A \times RRP + (G-A) \times LMP$

Where:

CMM\$	energy payment to generator (\$)
A	level of access to RRP determined by the CMM access allocation (MWh)
G	dispatch from the energy market (MWh)

The formulae above show that the two processes are analogous. However, unlike the CRM, the CMM does not use a dispatch run to determine access quantities (A) but instead does this algorithmically.. The CRM can be conceptually framed as a sophisticated access allocation method.

There are two key differences between the CMM and CRM.

1. Access allocation
   The CRM access allocation is a function of market participant bids submitted into the energy market. The CRM bases access allocation on a feasible dispatch. Access to the RRP is determined *before* the final physical dispatch as a function of the energy market.

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79 There are some fundamental requirements for the settlement residue including: The settlement residue is shared between available, participating generators. It is shared via flowgate entitlements, which are related to access through the constraint coefficients (entitlement = access MW x constraint coefficient). Allocated access must represent a feasible dispatch which binds the relevant constraint.

The CMM access allocation is algorithmic and only ensures feasibility on physically binding constraints. It would follow a set of logic rules and allocate access to the RRP depending on a generator's availability, and/or constraint coefficients and/or inferred economic costs. Access to the RRP is determined *after* dispatch as part of the settlements process.

2. Ability to opt out
   There is no 'opt out' in the CMM. Generators in a binding constraint would face the congestion charge and receive the congestion rebate. The CRM instead provides a market to incentivise participants to achieve an efficient dispatch by sharing the efficiency gain as a profit increase. It is voluntary but parties that opt out will forgo the CRM profits available.

Appendix F. Supporting detail for calculating indicative transmission hosting capacity values

Electranet's "connection opportunities for" generation and load

ElectraNet's 2021 TAPR sets out the outcomes of ElectraNet's high-level assessment of 'the ability of the existing transmission network nodes and connection points to accommodate new generator connections.'[80] The results are high-level indications in MW of the generation and load capacity that can be connected at different connections points:

Table 20 Indication of available capacity to connect generation and load on ElectraNet's network in 2024-45 (extract)

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	Very low daytime demand Sunny and still	Medium demand Sunny and still	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Eyre Peninsula (132 kV)					
Cultana	250	275	175	125	100
Whyalla Central	150	175	175	125	20
Yadnarie	250	275	175	150	100
Port Lincoln Terminal	250	275	175	150	100
Wudinna	80	80	80	80	20
Mid North and Riverland (132 kV)					
Bungama	175	200	80	80	100
Port Pirie	100	100	80	80	20
Baroota	0	20	20	0	0
Brinkworth	275	275	60	200	125
Clare North	150	150	40	150	80

ElectraNet assessed the anticipated thermal ability of the network to accommodate additional generation for four different system conditions (see Table 21 below). ElectraNet's assessment captures the impact of generation that is committed to connect to the SA transmission network, as well as the capacity expansion once Project EnergyConnect is commissioned.

At each location, the output of the new generator was gradually increased while adjusting interconnector flows within their limits to maintain the supply-demand balance. The output of the new generator was increased until a voltage limitation or a thermal overload was observed, with single credible contingencies considered. The impact of existing run back schemes was also considered (where practicable).[81] ElectraNet did not consider potential impacts on new or existing generators that could arise from any system strength limitations.[82]

80 ElectraNet, 2021 Transmission Annual Planning Report, p. 53.

81 ElectraNet, Transmission Annual Planning Report 2021, p. 52

82 ElectraNet, 2021 Transmission Annual Planning Report, p. 52.

Powerlink's Generation Capacity Guide

Similarly, Powerlink provides information for parties seeking connection to the transmission network in Queensland, including its Generation Capacity Guide (GCG). The current guide[83] broadly describes the current system strength environment and the opportunities for future investment in inverter-based generation. It also provides information on the local thermal capacity that may be available at different locations within Powerlink's network and the expected future utilisation of relevant major 'grid sections'. The GCG is published on Powerlink's website separate to the TAPR to facilitate updates to the GCG as required to make available the most up to date data for developers.

Similar to ElectraNet's approach, Powerlink calculated each connection point's thermal capacity by iteratively applying increasing levels of generation to the connection point (balanced by changing power flows on the Queensland to New South Wales Interconnector) and performing contingency analysis.[84] The thermal limit of a connection point was assessed as being reached when a rating breach was identified within the local network.

Table 21 Indicative connection point supportable generation capacities by zone

Zone	Voltage Level (kV)	Thermally supportable generation (MW)	Includes the substations
Far North	275	300-500	Chalumbin, Walkamin
	132	150-250	Chalumbin, Edmonton, Innisfail, Turkinje
Ross	275	800+	Ross
	132	150-400	Cardwell, Clare South, Ingham South, Tully, Yabulu South
North	275	800+	Nebo, Strathmore
	132	50-200	Alligator Creek, Bowen North, Collinsville North, Kemmis, Mackay, Moranbah, Newlands, Peak Downs, Pioneer Valley, Proserpine, Strathmore
Central West	275	200-800	Bouldercombe, Broadsound, Calvale, Lilyvale, Stanwell, Raglan
	132	100-300	Blackwater, Bouldercombe, Lilyvale, Bluff, Dysart

Powerlink's analysis is based on the existing and committed transmission network arrangements, as well as recent generator commitments.

Defining the boundaries of "zones" in the network

ElectraNet and Powerlink assessed the capacity of the network to support new generation based on physical impacts. ElectraNet determined the capacity to support new generation at each connection point, while Powerlink reflected the thermally supportable generation capacity according to "zones".

83 Current as at 31 July 2020: See https://www.powerlink.com.au/sites/default/files/2020-10/Generation%20Capacity%20Guide%20-%20August%202020.pdf

84 Powerlink, Generation Capacity Guide, August 2020, p. 5.

For its capacity outlook modelling,[85] AEMO disaggregates the existing five (pricing) regions of the NEM into sub-regions to reflect current and emerging intra-regional transmission limitations.[86] This facilitates AEMO's consideration of congestion between major load centres, given how it can be influenced by generation between regional reference nodes. The approach disaggregates some regions into one or more sub-regions, configured to identify major electrical subsystems within the electricity transmission network that allow free-flowing energy between transmission elements. Where key flow paths are identified that may materially constrain the transmission system from delivering energy between locations, this alternative sub-regional approach splits these areas from each other, to better identify the capacity of the intra-regional transmission system and the value of potential augmentations. A 10-sub-region structure is therefore applied to improve the granularity of optimisations that were previously assessed across five regions.

Table 22 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Central and North Queensland (CNQ)	Ross 275 kilovolts (kV)	Q1, Q2, Q3, Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	Southern Queensland (SQ)	**South Pine 275 kV**	Q7, Q8 and Q9
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	**Sydney West 330 kV**	-
Victoria	Victoria (VIC)	**Thomastown 66 kV**	V1, V2, V3, V4, V5 and V6
South Australia	South Australia (SA)	**Torrens Island 66 kV**	S1, S2, S3, S4, S5, S6, S7, S8 and S9
Tasmania	Tasmania (TAS)	**Georgetown 220 kV**	T1, T2 and T3

*Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.

Source: AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 118.

In this topology, the regional load and generation resources are split between the different sub-regions. Flow path transmission constraints are added to reflect the capability of the network.

Capturing the impact of diverse output profiles

The capacities of thermally supportable generation reported in Powerlink's GCG are based on a single generation dispatch assumption, being a typical winter noon load and coincident output for the existing and committed scheduled and semi-scheduled generation projects (see Table 23 below). Powerlink notes that '[t]he thermally supportable generation at a connection point may be substantially greater or lower with different generation patterns and load levels.'[87] The advantage of Powerlink's approach is simplicity.

85 As part of the ISP, AEMO undertakes capacity outlook modelling, which is 'the core process to explore how the energy system would develop in each ISP scenario, and to determine candidate development paths from which the optimal development path is selected': See AEMO, ISP Methodology 2021, p. 8.

86 AEMO, ISP Methodology 2021, p. 12

87 Powerlink, Generation Capacity Guide, August 2020, p. 5.

Table 23 Base winter noon generation dispatch assumptions for Powerlink's Generation Capacity Guide

Zone/Interconnector	Generation sent out (MW)
Far North	203
Ross	429
North	375
Central West	907
Gladstone	942
Wide Bay	158
Surat	387
Bulli	1,272
South West	1,308
Moreton	18
Qld-NSW Interconnector Southerly Flow (swing)	840
Terranora Interconnector Southerly Flow	60

In contrast, ElectraNet's assessment aims to reflect the impact on indicative hosting capacity of the diverse output profiles of generation connected to the network. Referring to Table 24 below, each scenario of ElectraNet's assessment assumed the varying output profiles of different generation types, corresponding to four different demand and weather conditions. For example, under a scenario of high summer demand, when it is sunny at noon, it is assumed a solar farm's output would be 0%, a wind farm's output at 90% capacity and a conventional generator's output at 5%.

Table 24 System conditions considered in the assessment of the ability of the SA transmission system to accommodate additional generation

System condition	SA demand (MW)	SA system losses (MW)	Heywood interconnector flow (MW)	Project Energy-Connect flow (MW)	Conventional generator output (% of capacity)	Wind farm output (% of capacity)	Solar farm output (% of capacity)
High summer demand sunny at noon	2,500	170	490 (import)	740 (import)	5%	50%	95%
High winter demand very windy and overcast	2,000	140	100 (export)	190 (import)	5%	90%	0
Medium demand sunny and still	1,400	100	600 (import)	470 (import)	2%	5%	90%
Very low daytime demand sunny and still	0	30	230 (export)	260 (export)	2%	5%	95%

A static version of AEMO's inputs and assumptions for its ISP may be able to be derived for informing hosting capacity assessments. This may have the benefit of promoting consistency between (a) hosting capacity calculated for the purposes of congestion zones and (b) the ISP outcomes. Such consistency would allow investors to better compare the information from these two sources.

AEMO applies the typical summer generation, in combination with the 10% Probability of Exceedance (POE) peak derated generation capacities across the seasons,[88] in a manner that reflects expected generator capabilities in the capacity outlook models. The definitions of these seasonal ratings and the temperature specifications are consistent with the ESOO, and described in the ESOO and Reliability Forecast Methodology Document:[89]

7.1 The winter capacity is used for all periods during winter ('Winter Reference')

7.2 The 10% POE demand summer capacity is applied to the subset of hottest summer days, using the same approach outlined in the ESOO and Reliability Forecasting Methodology Document ('Summer Peak')

7.3 For all other days in summer, the average of the typical summer and the winter rating is applied. This approach estimates the energy production capabilities of generators in summer, as opposed to focusing on the capacity available during peak periods which is more critical for unserved energy assessments ('Summer Typical').

These three categories could form the basis for the system conditions, including generator output profiles, that are assumed in a NEM-wide approach to calculating indicative transmission hosting capacity in congestion zones.

Reflecting network interdependencies

The thermally supportable generation capacity identified in Powerlink's assessment only relates to constraints on the local network around each connection point, including the network adjacent to the connection point and between the connection point and the main transmission system. Powerlink did not assess whether multiple generators in a region are likely to result in congestion on the backbone transmission network.[90]

In undertaking its assessment, ElectraNet considered the range of interconnector operating conditions set out in Table 24. For some system conditions that are not included in Table 24 above, such as times of very high wind generation output with moderate to low demand, the total dispatch of SA generation could be constrained by the capacity of the interconnectors to export electricity from SA. In determining the indicative hosting capacity, ElectraNet did not consider the potential impact of constraints in Victoria and New South Wales, or elsewhere in the NEM. It also notes that it did not consider 'any impact of co-optimised dispatch for generators connected on interconnector flowpaths'.[91]

As such, Powerlink and ElectraNet's hosting capacity figures should be read as reflecting capacity in one location *or* in another location, and *not* as the cumulative hosting capacity when combined.

For its capacity outlook modelling, AEMO has identified notional transfer limits between ten sub-regions represented at the time of 'Summer Peak', 'Summer Typical', and 'Winter Reference' in the importing sub-region. These notional transfer limits are presented in the table below. The forward direction of flow is typically in the north or west direction and is consistent with the flow path name.

88 The typical summer capacity is used to represent the capacity that would be available under regular summer conditions, based on the 85th percentile of observed maximum daily temperatures for all reference years between December and March. Further details on this approach are available in the ESOO and Reliability Forecasting Methodology Document, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

89 Seasonal definitions reflect those specified in the 2020 ESOO; that is, summer ratings are applied between November to March and winter ratings between April to October.

90 Powerlink, Generation Capacity Guide, August 2020, p. 5.

91 ElectraNet, 2021 TAPR, p. 56.

Table 25 Notional transfer capabilities between sub-regions

Flow path (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)		
	Summer Peak	Typical Summer	Winter Reference	Summer Peak	Typical Summer	Winter Reference
CNQ – GG A	700	700	1,050	750	750	1,100
SQ – CNQ	700	700	1,000	2,100	2,100	2,100
NNSW – SQ ("QNI") B	685	745	745	1,205	1,165	1,170
NNSW – SQ ("Terranora")	0	50	50	130	150	200
CNSW – NNSW	910	910	910	930	930	1,025
CNSW – SNW	7,525 (6,125C)	7,525 (6,125C)	7,625 (6,225)D	6,125D	6,125D	6,125D
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590
VIC – SNSW E	870	1,000	1,000	400	400	400
SNSW – SA	800	800	800	800	800	800
VIC – SA ("Heywood") F	650	650	650	650	650	650
SNSW – SA & VIC – SA combined	1,300	1,300	1,300	1,450	1,450	1,450
VIC – SA (Murraylink)	220	220	220	100	200	200
TAS – VIC	478	478	478	478	478	478

Note: Forward and reverse directions are as referred in the first column of this table.

A. CNQ-GG limits are heavily influenced by the amount of generation in northern and central Queensland, particularly at Gladstone. The provided transfer limit is a representation with typical generation output from Stanwell and Calvale and reduced generation at Gladstone. This limit will be further reviewed with hourly simulation results.
B. QNI Minor is a committed project and is included in the transfer capability.
C. The CNSW to SNW transfer limit is reduced to 6,125 MW in the absence of Eraring or Vales Point generation.
D. Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. For DLT modelling, a transfer limit of 6,125 MW is assumed for this limit, and will be reviewed if it becomes material.
E. VNI Minor is a committed project and is included in the transfer capability.
F. The Heywood interconnector currently operates at 600 MW forward capability and 550 MW reverse capability. AEMO and ElectraNet are working to release the transfer capability to its designed capability of 650 MW in both directions.

To identify transfer limits for each seasonal condition, AEMO gathers input data from asset owners, for example network ratings for various ambient temperature conditions, any runback schemes or SPSs. AEMO also gathers historical operational data for the network. AEMO then consults with the local TNSPs to understand potential limiting factors and either AEMO or the TNSP undertakes power system analysis to evaluate the impact of each of the limiting factors on the transfer capacity. This includes:

1. A mixture of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength assessments, depending on the sub-region, and
2. Testing worst-case conditions and typical conditions, and a selection of appropriate demand and generator dispatch conditions.

AEMO selects the most binding transfer limit. For example, if there is a transient stability issue which limits flow between sub-regions to a particular MW value, but that value is higher than the MW flow value for the voltage stability limit for that sub-region, then the voltage stability limit will be used to set the transfer capability.[92]

Additional information to accompany network congestion metric for investors

The NER Clause 5.12.2(c)(3) requires TNSPs to report the forecast of constraints and inability to meet network performance requirements. This reporting must at least include:

(i) a description of the constraints and their causes;

(ii) the timing and likelihood of the constraints;

(iii) a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and

(iv) sufficient information to enable an understanding of the constraints and how such forecasts were developed;

This information identifies the transmission elements where flows have been at, or close to, the limits. Capacity could be limited due to the power flows reaching:

- The maximum rating of a single transmission element, such as a transmission line or a transformer;
- The combined capacity of a group of transmission elements, such as several parallel transmission lines constituting inter regional links; and
- The limits set by system wide considerations such as voltage, transient or oscillatory stability.

Further, transparency around the cause of transmission limits – i.e. whether it is based on a thermal constraint or a voltage constraint – can help investors determine whether they are willing to fund a solution to alleviate the constraint.

By way of example, TransGrid's 2021 TAPR provided details of transmission constraints for the previous 12 month period (1 March 2020 – 28 February 2021).

Table 26 Constraints operating at the capability limit

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
1	V^^N_NIL_1	33:11:40	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines
2	N_X_MBTE2_B	31:15:35	Unit Zero	Terranora Interconnector	Lower limit on Directlink, two cables out
3	N^N-LS_SVC	26:10:40	Voltage Stability	Terranora Interconnector	Avoid voltage collapse on trip of Armidale to Coffs Harbour (87), Lismore SVC out
4	N_X_MBTE_3B	21:08:45	Unit Zero	Terranora Interconnector	No flow on Directlink, all three cables out

Source: Transgrid, Transmission Annual Planning Report 2021, Table A5.1 p.149.

92 AEMO, ISP Methodology 2021, pp. 16-17.

In their TAPRs, TNSPs also provide information around emerging and future constraints. For example, in its 2021 TAPR, ElectraNet highlighted the limitations that could bind looking forward, based on a 10-year forecast of generator expansion. The information notes the forecast binding hours and potential mitigating projects.

Limitation	Timing indication	Affected corridor	Forecast average binding hours (hrs/year) [22]		Potential mitigating project(s)
			2021-22 to 2030-31	2021-22 to 2040-41	
Loss of Templers West 275/132 kV transformer overloads Para 275/132 kV transformer	After 2023	Robertstown – Adelaide	853	1025	Install second Templers West 275/132 kV transformer
Loss of Robertstown 275/132 kV transformer overloads Waterloo – Waterloo East 132 kV	After 2023	Robertstown – Adelaide	300	845	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Robertstown – Para 275 kV overloads Waterloo East – Waterloo 132 kV	After 2023	Robertstown – Adelaide	119	473	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of one 275 kV circuit between Davenport and Cultana overloads the other 275 kV circuit	After 2022	Davenport – Cultana	66	90	Remove plant rating limitations on the Davenport – Cultana 275 kV corridor

Appendix G. Stakeholder feedback on shortlisted models

In its May 2022 Consultation Paper, the ESB sought feedback on four shortlisted models that had been developed through significant stakeholder consultation.

The content of this directions paper reflects the ESB's work with stakeholders to develop these models. A key focus of this work has been to strike a balance between providing flexibility to new participants to connect where they want in the network and protecting investors' that have already connected to the network from excessive congestion.

The shortlisted models were presented in the consultation paper as follows:

Investment timeframes	Operational timeframes
Congestion zones with congestion 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 Investors that connect in uncongested locations receive priority rights.	**Congestion relief market (CRM)** Changes to the market and settlements to provide separate revenue streams for energy and congestion relief.

Table 3.1 provides an overview of the current status of each shortlisted model. The table splits the "congestion zones with congestion fees" model into two parts: the enhanced information component and the congestion fees component. Connection fees have been re-named to "congestion fees" to more accurately reflect that these fees aim to provide a measure of a new project's impact on congestion in the network.

Table 3.1 Status of shortlisted models

Model	Stakeholder feedback	Status
Investment timeframes		
Enhanced information	Broad stakeholder support as a "no regrets" option.	This reform would be applied in combination with one of the other investment timeframe models. This paper seek stakeholders' feedback on the network information that investors would find most useful, including any metric of network hosting capacity or congestion.
Congestion fees	Support from customers, networks and a minority of generators.	This concept is being developed via the "congestion fees" variant of the hybrid model. This paper sets out the ESB's developed thinking on this variant, presenting a number of options for determining both how congestion fees will be calculated and the associated process.
Transmission queue	A small number of investor representatives support this model, but most stakeholders are concerned that it would stifle investment and result in inefficient dispatch outcomes.	This concept is being developed via the "priority access" variant of the hybrid model. The combination of the priority access variant with CRM achieves efficient outcomes and enables investors to manage access risk. The hybrid model has been developed and the thinking presented in this paper for stakeholder feedback. Considerations include the form of the queue right, the allocation of queue positions and the duration of the rights.

Operational timeframes		
Congestion relief market	Generators, developers and storage providers were generally supportive of the model, however customers were concerned about the cost.	The ESB has significantly developed detailed design of the CRM, with its current thinking set out in this paper. The ESB has developed detailed design options around, for example, the scope of participants under the CRM, arbitrage opportunities for generation and the treatment of interconnectors. As this model is new and untested, we may identify challenges that lead us to revert to the CMM.
Congestion management model	While customers and networks supported this model, it was opposed by most generators and their representatives.	In the case that the implementation costs for the CRM are too high or other challenges arise with that model, the ESB will continue to develop the CMM in the background as a second choice.

This appendix provides an overview of each shortlisted model as it was presented in the May 2022 Consultation Paper. It goes on to summarise the stakeholder feedback on the model to the Consultation Paper, and describe how the ESB's thinking has evolved since the consultation paper.

Congestion zones and congestion fees

Overview of model

The Congestion zones with congestion fees model aims to provide investors with clear up-front signals about which network locations have available hosting capacity. The model leverages a planning process to segregate the transmission system into zones that would 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 which parts are already full.

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 located in a co-ordinated 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 co-efficient. 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 risks associated with inefficient subsequent connections.

The locational signal could take the form of a congestion fee. A published schedule of congestion 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 of the model, generators would commit to pay a charge that reflects the long run marginal cost of congestion at their chosen location. The fee would be fixed at the time of connection however generators could negotiate how to pay this over the life of the asset.

Stakeholder feedback

Stakeholders were generally supportive of more information being provided regarding network congestion.[93] Support for enhanced information included the publication of a Transmission Statement of Opportunities to provide an AEMO-developed overview of areas of the transmission network where there is available hosting capacity.[94]

Other suggestions proposed by stakeholders regarding this model included:

- The traffic light system identifying available, almost full and over-subscribed areas of the grid[95]
- Mandatory congestion studies[96], and
- AEMO sharing a dynamic open access model to assess congestion impacts on projects.[97]

The proposal for congestion fees was more contentious. Fees were supported by Energy Consumers Australia, the Energy Users Association of Australia, who noted the benefits of a more coordinated approach to generation investment.[98] Some generators provided in principle support for congestion fees or aspects of the model, noting the early stage of development that the model was in.[99] However, as it involves the imposition of a new charge, the majority of generators oppose this option.[100] Some of the concerns raised include that congestion fees will lead to inefficient investment decisions and a more complicated connections process.

Some key areas of feedback on this part of the model included the value of the connection fee, the use of funds from the connection fee, potential modifications to the design, and alternative options.

Regarding the value of the connection fee, some of the proposals for the metric used to calculate the fee included:

- The net present value (NPV) of the cost of congestion created by the connecting asset.[101]
- The long-run incremental cost of network investment.[102]
- The expected value of CMM rebates that the generators receive in dispatch.[103]
- The costs to deliver the agreed maximum level of congestion that a generator is prepared to accept.[104]

Regarding the use of funds arising from the congestion fees, the two main proposals were:

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[93] Submissions to the consultation paper: CEC, p. 36, Flow Power, p. 2 EnergyAustralia, p. 1.

[94] Submission to the consultation paper: Iberdrola, p. 2.

[95] Submission to the consultation paper: NEOEN, p. 8.

[96] Submissions to the consultation paper: CEC, p. 19; Tesla, p. 6.

[97] Submission to the consultation paper: CEC, p. 19.

[98] Submissions to the consultation paper: ECA, p. 2; EUAA, p. 3.

[99] Submissions to the consultation paper: AEC, p. 2; Delta Electricity, p. 2; Shell Energy, pp. 3-4.

[100] Submissions to the consultation paper: CEC, p. 42; Iberdrola, p. 4; Tilt Renewables, p. 2.

[101] Submission to the consultation paper: Finncorn Consulting, p. 9.

[102] Submission to the consultation paper: AEC, p. 3.

[103] Submission to the consultation paper: AGL, p. 2.

[104] Submission to the consultation paper: Shell, p. 3.

- Some stakeholders supported the use of fees to fund transmission augmentation to reduce future congestion or offset TUOS charges.[105]
- Other stakeholders supported the use of funds to upgrade the network.[106]

Some stakeholders raised some potential modifications to the design of the connection fee. These included:

- Establishing a minimum connection fee to ensure that all generators are making some contribution to offset network costs.[107]
- For dispatchable assets, offer a choice to face a lower (or zero) connection fee with obligations not to be dispatched in competition with renewables, or to face the identical connection fee.[108]
- Calculate the cost over a shorter 4-5 year period due to the inherent uncertainty in calculation and forecasting.[109]
- Create a dynamic, rather than static charge and/or allowing for periodic reviews to adjust the fee to reflect changes in congestion due to network augmentations or inaccurate forecasting.[110]
- For the TNSP to make a commitment regarding expected congestion in return for the connection fee.[111]

Finally, EnergyAustralia proposed some alternative design options to the congestion fees, including:

- Limiting access similarly to the REZ physical access arrangements in the Central-West Orana REZ.
- Allowing participants to self-remediate congestion.
- Mandatory participation in control schemes.

Status of model

The "congestion zones with congestion fees" model has since been split into two parts: the enhanced information component and the congestion fees component.

The ESB has developed its thinking around the information that could be brought together, on a consistent NEM-wide basis, to provide investors with a clearer view of the level of network capacity across the transmission network. This information could take multiple forms, with each option containing its own trade-offs. Enhanced information is not proposed as a standalone solution as it does not remove incentives for inefficient investment.

The ESB has developed detailed design of the congestion fee framework in consultation with the Technical Working Group. This paper sets out the various design choices around both the method for calculating the fees and the process for undertaking this calculation.

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[105] Submissions to the consultation paper: Finncorn Consulting, p. 5; EUAA, p. 3; Engie, p. 2.

[106] Submission to the consultation paper: Delta Electricity, p. 2.

[107] Submission to the consultation paper: EUAA, p. 3.

[108] Submission to the consultation paper: Finncorn Consulting, p. 8.

[109] Submission to the consultation paper: AGL, p. 2

[110] Submission to the consultation paper: ENA, p. 3.

[111] Submission to the consultation paper: Alinta, p. 2.

Regarding the latter, the ESB has set out the potential options for integrating this process with the existing transmission connections regime.

Transmission queue

Overview of model

The transmission queue model establishes a queue that confers priority rights, either to be allocated rebates in the CMM or to establish who buys and sells congestion in the CRM. 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).

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. In the May consultation paper, the ESB proposed a modification to the way that queue numbers confer priority rights on market participants, however other aspects of the model could form the basis of an investment timeframe access solutions.

The original design proposed to trigger the queue mechanism in the event of a binding constraint and tie-breaking bids. When multiple generators have the same bid price and MLF, the model proposes that the dispatch algorithm would dispatch based on their order in the transmission queue. An issue with this approach is that tie-breaker rules rarely come into play due to the impact of generator constraint coefficients. Instead, race to the floor bidding and the precision of coefficients gives rise to "winner takes all" outcomes. As a result, it isn't clear that the original design would be effective in protecting the access of generators, even those with low queue positions.

The ESB has been exploring modifications that apply the queue positions in ways that help investors to manage their access risk, including:

- Allocated rebates in a CMM model
- Determine the eligibility of generators to sell congestion relief in the CRM, 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.

Stakeholder feedback

There was limited engagement from stakeholders on the Transmission Queue Model (TQM). Generally, stakeholders were not supportive of the transmission queue model.[112] Some stakeholders were supportive of the transmission queue model or elements of the model.[113] The CEIG noted its support for the original transmission queue model design as per its original submission, rather than the updated design proposed by the ESB.[114]

Some of the key points raised by stakeholders include:

[112] Submissions to the consultation paper: Alinta, p. 1; AEC, p 3; AGL, p. 2; CEC, p. 42; Delta Electricity, p. 2; EnergyAustralia, p. 1; ECA, p. 3.

[113] Submissions to the consultation paper: Tilt Renewables, p. 1; Shell Energy, p. 4.

[114] Submission to the consultation paper: CEIG, p. 1.

- The potential for the model to lead to inefficient dispatch outcomes and increased costs to consumers.[115]
- The model introduces an overly complex process of the expression of interest (EOI) and auction for an unknown financial right during periods of congestion.[116]

The model may impact contract liquidity.[117]

- A single national queue bypasses the local planning and investment knowledge of TNSPs, while a more granular implementation will be cumbersome and fails to recognise the meshed nature of the network.[118]

Despite the general lack of support, some stakeholders also provided design suggestions if the model was pursued by the ESB. These included:

- Rounding of constraint coefficients should be considered further.[119]
- If the detrimental impact on new developments appears too severe, an adjustment can be made where existing investments are not completely insulated from increased congestion. Instead of doing no harm, new generation could be allowed to do a small amount of harm to existing participants.[120]
- Queue positions could apply within REZs only and inform the allocation of rebates.[121]
- A limited right to CMM rebates until other assets with lower queue positions are placed in a net position (after LMP + rebate) that is no worse than if the higher queue position assets were not dispatched.[122]
- Generators should be allowed to fund transmission upgrades to benefit from improved queue positions.[123]
- Storage should be treated the same as other generators in the model.[124]
- Queue positions could take the form of small advantages to the constraint coefficients of projects with better queue positions.[125]

Status of model

A concern that the ESB and stakeholders have with the TQM in its original form is the impact of the physical access rights on efficient dispatch. High-cost generators that receive a favourable queue position due to early investment will be able to have enduring priority in physical dispatch over lower cost later joiners.

The most obvious example of this is that an existing thermal plant would be granted a queue position of zero, with later joining renewable generator having a queue position that is greater than zero.

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[115] Submissions to the consultation paper: Finncorn Consulting, pp. 10-11, Delta Electricity, p. 2.

[116] Submissions to the consultation paper: Engie, p. 3; Shell Energy, pp. 4-5;

[117] Submission to the consultation paper: NEOEN, p. 6.

[118] Submission to the consultation paper: ENA, p. 4.

[119] Submissions to the consultation paper: CEIG, pp. 7-9; Tilt Renewables, p. 4.

[120] Submission to the consultation paper: Tilt Renewables, p. 3.

[121] Submission to the consultation paper: ACEN, p. 3.

[122] Submission to the consultation paper: Finncorn Consulting, p. 10.

[123] Submission to the consultation paper: Delta Electricity, p. 6.

[124] Submission to the consultation paper: Delta Electricity, p. 6.

[125] Submission to the consultation paper: Iberdrola, p. 6.

During periods of congestion on the network, the thermal plant will enjoy priority physical dispatch over the renewable plant, despite its costs potentially being much higher. This does not lead to the least cost overall dispatch, which is a key objective of the TAR work program.

In addition to the concerns regarding inefficient dispatch above, the ESB holds concerns over the feasibility of integrating queue positions into physical dispatch. A move to this type of model would require significant changes to the configuration of the dispatch engine. Similar models have been tried in other jurisdictions, including Western Australia. Parties familiar with the Western Australian physical dispatch scheme have noted the unsuitability of such a model at a large scale.

These concerns can be overcome, while still achieving the intent of the model, by applying the TQM in combination with an operational timeframe model. In this case, the queue would confer priority rights to either CMM rebates, or to sell congestion relief in the CRM. This is described in more detail in section 4.2.2.

Congestion relief market (CRM)

Overview of model

The CRM is a new market that incentivises additional efficient dispatch outcomes in addition to those produced by the existing energy market. The proposed design is set out in Chapters 3 and 4 of this directions paper.

The ESB initially had concerns as to whether the CRM would be feasible to run in the dispatch process. The ESB has engaged with stakeholders, particularly the Clean Energy Council and AEMO, to further develop the CRM design so that it is technically feasible.

Stakeholder feedback

Generators, storage providers and their representatives were generally supportive of the CRM.[126]

Some stakeholders were not supportive of the model. Some concerns raised by parties that were not supportive of this model included:

- Disorderly bidding could continue in the energy market under this model, with no certainty of net efficient outcomes from the voluntary CRM.[127]
- There is a risk that the market for congestion relief could be shallow on individual constraints, which may not provide enough certainty for storage and flexible load.[128]
- There is no international precedent for a model like the CRM.[129]

The ESB notes that since the publication of the consultation paper, a significant amount of work has been undertaken between the ESB and the technical working group to further develop the CRM. The outcomes of this work are discussed in more detail in chapter 4.

Generators, developers and storage providers were generally supportive of the model, noting that:

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126 Submissions to the consultation paper: CEC, p. 34; Alinta, p. 2; Delta Electricity, p. 3; Edify Energy, p. 1; Iberdrola, p. 8; Origin Energy, p. 2; Tesla, p. 4.

127 Submissions to the consultation paper: Engie, p. 3; Finncorn consulting, p. 14.

128 Submission to the consultation paper: Finncorn consulting, p. 14.

129 Submission to the consultation paper: Finncorn consulting, p. 15.

- The CRM as a voluntary market allows for flexible management of financial exposure.[130]
- The CRM should be subject to a cost-benefit analysis to see if implementation costs would reduce any benefits of introduction.[131]
- The CRM provides a clear revenue path for batteries.[132]

Status of model

The ESB considers that the CRM design will be the immediate focus in operational timeframes. Chapters 3 and 4 of this directions paper sets out the ESB's progress in developing the detailed design of this model. While this is the case, the ESB notes that the CRM is still in a relatively formative stage.

A key issue relates to its implementation costs. The CRM design affects multiple systems including bidding, pre-dispatch, dispatch and settlements. The design choices in this paper will clarify the proposed design specification and allow AEMO to better estimate the costs of implementation. If issues arise that mean the CRM design becomes infeasible or unduly costly, the ESB may consider other models, including the CMM, in operational timeframes.

Congestion management model (CMM)

Overview of model

The Congestion Management Model (CMM) establishes a single, combined-bid energy and congestion market. In this model, generators and batteries would receive rebates if congestion occurred. An overview of this model is provided in Appendix D above, along with a key design choice regarding the method for allocating congestion rebates.

Stakeholder feedback

There was limited support for the CMM among generators, storage providers and their representatives.

Consumer groups were generally supportive of the CMM. These groups noted that:

- The CMM will most effectively utilise the new and existing transmission network, allowing the system to deliver more efficiently for consumers.[133]
- The CMM with universal rebates provides a robust, transparent and equitable means by which market participants can manage congestion risk should it become material.[134]

Some other parties were also of the CMM, noting:

- The CMM with universal rebates is largely intended to encourage more efficient dispatch while making no generator financially worse off.[135]

Some generators and storage providers were not supportive. Some of the key issues raised by these parties included:

[130] Submission to the consultation paper: Tilt Renewables, p. 6.

[131] Submissions to the consultation paper: Iberdrola, p. 8; AGL, p. 2; Origin Energy, p. 2.

[132] Submission to the consultation paper: Tilt Renewables, p. 6.

[133] Submission to the consultation paper: ECA, p. 2.

[134] Submission to the consultation paper: EUAA, p. 3.

[135] Submission to the consultation paper: ACEN, p. 2.

- The CMM rebates are arbitrarily and administratively set.[136]
- It is not clear that generators would be fully hedged against basis risk.[137]

In relation to rebate allocation, stakeholders noted that key considerations for the chosen model should be the need to manage basis risk, as well as increased certainty for generators. Some stakeholders also noted that the allocation metric may influence some generator bidding behaviour to be inefficient.

In relation to the impact on storage and flexible load, storage providers noted a preference for the CRM due to the CRM providing a stronger locational signal for batteries with dispatch as opposed to a post-settlement mechanism. Stakeholders noted that a key decision-making factor is whether BESS can take advantage of high prices in energy and FCAS markets when they arise by dispatching.

Status of model

Whilst consumer groups were generally supportive of CMM, given the lack of support from industry stakeholders who would participate in the model, and given its similarity to the CRM and that its design is already more advanced than the newer, industry-proposed models under consideration, the ESB has focused its efforts on developing the CRM instead. We have, however, engaged NERA to model the impacts of the CMM (and CRM) in order to give stakeholders a better understanding of the model, and the different design choices within it.

As noted above, the ESB considers the CRM will be the primary model for consideration in operational timeframes. In the case that the implementation costs are too high or other challenges arise with the CRM, the ESB will continue to develop the CMM in the background as a second choice.

[136] Submission to the consultation paper: CEC, p. 33.

[137] Submission to the consultation paper: Origin Energy, p. 1.

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