ENERGY SECURITY BOARD

Transmission access reform

Modelling the congestion relief market

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List of abbreviations

AEMO	Australian Energy Market Operator
CEC	Clean Energy Council
CEIG	Clean Energy Investor Group
CMM	Congestion management model
CRM	Congestion relief market
ESB	Energy Security Board
GW	Gigawatt
GWh	Gigawatt hour
ISP	Integrated System Plan
LGC	Large scale generation certificate
LHS	Left hand side of a constraint equation
LMP	Locational marginal price
MLF	Marginal loss factor
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
PEC	Project EnergyConnect
PPA	Power purchase agreement
REZ	Renewable Energy Zone
RHS	Right hand side of a constraint equation
RRN	Regional Reference Node
RRP	Regional Reference Price
SRMC	Short run marginal cost
VRE	Variable renewable energy

Executive Summary

The Energy Security Board (ESB) is working to develop a package of reforms to manage congestion in the National Electricity Market (NEM). The ESB engaged NERA Economic Consulting (NERA) to conduct detailed modelling on two market designs that would promote operational efficiency; the congestion relief market (CRM) and the congestion management model (CMM). The ESB has recommended the CRM design as part of its transmission access reform model.

As NERA's detailed modelling report is technically dense, this paper identifies key findings from the detailed modelling with a focus on the CRM design. It is designed to translate technical terms into the market design concepts that stakeholders recognise.

Modelling congestion and the CRM is an extremely difficult task but has generated valuable insights.

The modelling methodology undertaken by NERA is highly granular to simulate congestion outcomes; every node and line in the NEM is modelled and dispatch is calculated for each half-hour in the year. This is more granular than the models that the Australian Energy Market Operator (AEMO) uses to develop its Integrated System Plan (ISP). It requires modelling both short-term inputs such as generator offers and aligning the model with the ISP's long-term outputs such as generator entry and exit and transmission development.

The modelling has been challenging but it has generated valuable insights as to the benefits of the CRM, how the CRM is likely to operate in practice and broad trends about how CRM outcomes may evolve through the energy transition. The ESB has placed some reliance on modelling outputs in the short term (2023-24) as input assumptions to the cost benefit analysis. In the longer term (2033-34), the ESB considers the most useful outputs are the trend (qualitative) outcomes given the nature of such detailed modelling, the potential for variations in inputs over the ten-year horizon and some specific modelling difficulties.

The current market design is not well placed to support the changing dynamics.

Modelling shows the complexity, cost and risks to efficiency of operating the market under the current design into a low carbon future. As the penetration of variable renewable energy (VRE) increases, congestion will become more common and more difficult to manage under today's market design.

The modelling highlights that significant congestion arises near regional boundaries and affects interconnector flows. Congestion is a national, not a localised, problem. Today's market design will limit the efficient use of national transmission network investments. In the absence of reform, it will be increasingly necessary to clamp the interconnectors to avoid customers having to fund revenue shortfalls. The materiality of this issue is a new insight not previously illustrated by simplified worked examples of a looped network flow within a region.

The CRM design results in the efficient use of interconnectors.

The CRM design was originally conceived as a mechanism to encourage bilateral trades between parties behind a constraint (i.e. between a buyer and seller of congestion relief). It was limited in scope involving local trades. The CRM design has evolved into a broader market solving multiple constraints across the network. The need for interconnector clamping in the physical dispatch would be substantially mitigated by the proposed reforms due to changes in how generators are compensated.

The modelling highlights that the scope and materiality of CRM trading is dominated by inter-regional congestion. The physics of the network can create a gearing effect which multiplies up the impact on dispatch outcomes, e.g. a 1MW adjustment for a generator in one region could need balancing by up to 14MW elsewhere in the system (maximum ratio). The CRM unwinds the inefficient counter-price flows that occur in today's energy market and creates trading opportunities for generators providing the balance of energy.

The CRM design will lead to a significant reduction in dispatch costs.

Stakeholders are correct to point out that as zero marginal cost VRE enters the system, there will be higher levels of curtailment at low prices in future. However, NERA's modelling suggests that dispatch inefficiency becomes more costly because there are increased instances of congestion and it results in non-VRE alternatives being dispatched.

The dispatch saving is higher in 2033 compared to 2023 since most of the must-run coal capacity has retired and gas has displaced coal at the margin. There are also more opportunities for efficiency gains from the increased interconnector flows enabled by the QNI expansion.

The efficiency gain from lower dispatch costs is shared between generators and customers.

The efficiency gain is shared between CRM participants (generators and scheduled load) and customers through an "efficiency dividend". The "customer" component relates to a change in settlement residue which is passed through to customers. All CRM participants will receive an efficiency dividend; non-participants[1] will not. The CRM still provides efficiency gains and dividends even if there is substantial non-participation, although these gains are reduced.

The efficiency dividend from capital cost savings is excluded from modelling.

The scope of the NERA modelling is limited to simulating dispatch and pricing outcomes. It adopts the optimal development path of the ISP 2022 which has already successfully co-optimised generation and transmission. In practice, without access reform, the ideal scenario modelled in the ISP will probably not happen without access reform. The modelling does not quantify the savings in capital costs e.g. efficiencies created by the CRM will lead to a lower requirement for storage capacity. And it understates the operational inefficiencies when the resulting sub-optimised generation and transmission investment generates more congestion and greater opportunity for disorderly bidding.

The CRM design avoids wealth transfers associated with changes to RRPs or access quantities.

The CRM design introduces a new market that supplements and complements the existing energy market. The reform encourages bidding incentives in the CRM that are more cost reflective and achieves a primary objective of transmission access reform for dispatch efficiency.

It was an open design choice in the Directions Paper on the formulation of the RRP. On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to keep RRPs from the energy dispatch (rather than the CRM).

Compared to the alternative CMM, the CRM design avoids changes to RRPs and access quantities which would otherwise create 'winners' and 'losers' from the reforms. Instead, they would continue to be determined by the existing energy market dispatch.

NERA's detailed modelling reflects the status of the ESB's shortlisted models at the time of scoping.

NERA's report includes significant detail on the intricacies of modelling the CMM and RRPs from the energy market and CRM dispatches. Appendix A provides a summary of the CMM approach and outcomes. Readers can refer to the full detailed modelling report as needed.

The ESB is applying the lessons learned from modelling to its technical implementation plan.

The ESB technical team is developing a CRM prototype and has applied historic data from NEM dispatch intervals as test cases. NERA's modelling has helped to indicate how the CRM trading will evolve as the generation and transmission mix develops, and how to future proof the CRM design. AEMO is already considering its policy options regarding interconnector clamping as part of Project Energy Connect (PEC) and has released a consultation paper.[2] This will be an area of ongoing investigation and consultation.

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1 Non-participants refer to non-participating scheduled resources.

2 AEMO, Project Energy Connect Implementation Paper, released 15 November 2022.

1 Introduction

1.1 Purpose of document

The ESB is working to develop a package of reforms to manage congestion in the National Electricity Market (NEM).

The ESB engaged NERA Economic Consulting (NERA) to conduct detailed modelling on two market designs that would promote operational efficiency; the congestion relief market (CRM) and congestion management model (CMM).

The CRM design was the preferred model in the ESB's Directions Paper,[3] published in November 2022. The CMM was one of the previously shortlisted models in an earlier consultation paper.[4]

This paper includes:

- key findings identified from detailed modelling with a focus on the CRM design (ESB)
- detailed modelling report including the CRM and CMM (NERA Economic Consulting)

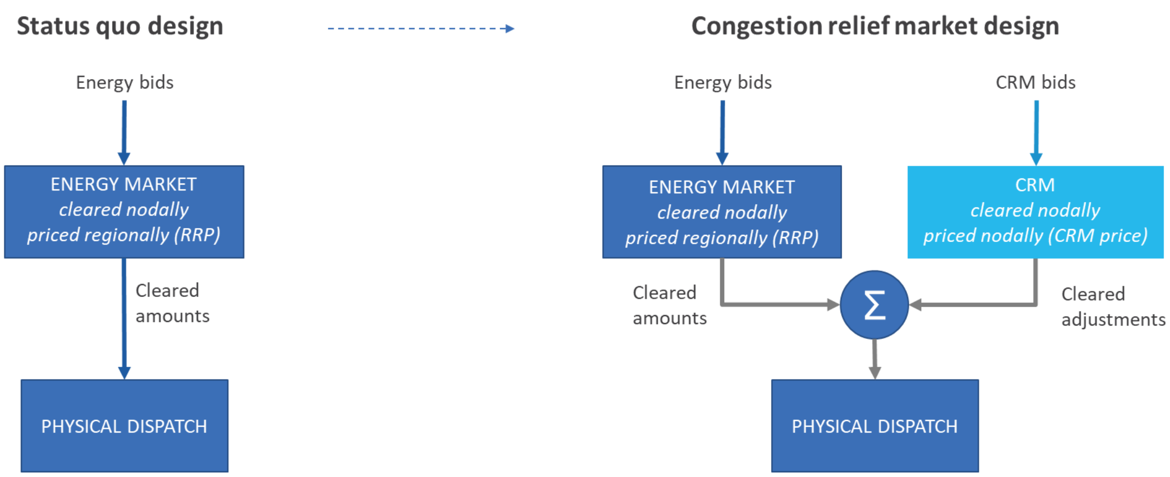
This chapter summarises the key features of the CRM design, compares the bidding incentives for today's energy market and the proposed CRM design and provides an abridged version of NERA's modelling approach.

Appendix B provides a short discussion of the scenarios and insights for the CMM. Readers should refer to the full detailed modelling report for further details.

1.2 Congestion relief market design

The CRM design introduces a new spot market shown in Figure 1. It supplements and complements the existing spot market (referred to here as the 'energy market').

Figure 1 Market architecture moving from status quo to a future CRM design



Source: ESB.

3 https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf November 2022

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

1.2.1 Participant bids

NEM participants already submit a set of bids into the energy market. Those participating in the CRM would submit a second set of bids. The format of the CRM bids will be similar to the energy market (i.e. full CRM supply / demand curves for capacity). But the CRM bids themselves may be the same as, or different from, the energy market bids.

The CRM is a voluntary trading market. Participants can choose whether or not they participate. Those wishing to trade in the CRM will need to notify AEMO that they are 'opting in'.

Those who do not participate will trade as they do today; submitting bids to the energy market and following the energy dispatch targets.

1.2.2 Dispatch outcomes

There are two dispatches.

- the existing energy market dispatch
- the new CRM dispatch.

The CRM dispatch runs immediately after the energy market dispatch. The quantities cleared are referred to as CRM adjustments and the clearing prices are referred to as CRM prices.[5]

Unlike energy spot prices, the CRM prices are nodal (i.e. prices for generators may vary depending on their location). Irrespective of CRM outcomes, generators are still paid RRP on their energy market quantities. Only adjustments between the CRM and the energy market are settled at the CRM price.

The physical dispatch target for each generator is the sum of the original energy market dispatch target and the CRM adjustments. CRM adjustments can be positive or negative so the physical dispatch target might be higher or lower than the original energy dispatch target.

1.2.3 RRP outcomes

There are two sets of RRPs generated in the CRM design:

- RRPs from the energy dispatch
- RRPs from the CRM dispatch.

The ESB presented a design choice in the Directions Paper as to which of these RRPs to use for energy settlement. On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to keep RRPs from the energy dispatch. This will be the assumption applied to the CRM design going forward. The ESB will release papers in future on the ESB response to stakeholder feedback including the selected choice and rationale for design decisions.

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5 CRM prices are referred to as locational marginal prices (LMP) in the NERA detailed modelling report. The CRM price as proposed by the Clean Energy Council and LMP share the same formulation. They are based on the bids and offers of the CRM participants and represent the market clearing prices. They are specific to each location and hence called LMPs (or nodal prices).

1.2.4 Terminology of buyers and sellers and products

In the original Edify Energy proposal,[6] bids are received from buyers (receivers) and sellers (providers) of congestion relief. For example, a seller could be a generator behind a constraint that reduces its output. They would be paid for congestion relief as compensation for lost RRP revenue.[7]

The ESB CRM design is based on the modified version from the Clean Energy Council (CEC).[8] Under this design, the CRM instead clears adjustments in dispatch quantities, compared to the dispatch outcomes of the energy market. A generator that reduces output does not lose any RRP revenue, but it now pays to buy energy from the CRM. This framework changes the terminology. A CRM seller sells energy (buys congestion relief) and a CRM buyer buys energy (sells congestion relief).

The net effect of these payment structures is the same; a generator that reduces its energy output profits from avoided costs, just like the Edify proposal.[9] Appendix A explains how the CRM design has evolved from the Edify Energy proposal, to the CEC modified version and the ESB's Directions Paper. It clarifies the points of similarity and difference.

The concept of buying and selling congestion relief continues to be helpful to explain the policy principles and economic concepts (e.g. for the cost benefit analysis). But it is less helpful for parties to determine how they might optimally trade. This paper focuses on bidding incentives and assumptions. It adopts terminology which is consistent with the formula for settlement and enables stakeholders to understand how they would develop their bidding strategy.

In this paper, the term of buyer and seller is applied as follows:

- CRM buyers:
  - consume energy (scheduled load) or
  - reduce energy outputs (generators).
- CRM sellers:
  - sell energy (generators) or
  - reduce consumption (scheduled load).

6 Edify Energy, Response to ESB's Project Initiation Paper, June 2021.

7 The settlement formula for Edify Energy's proposal is as follows; *Settlement $ = dispatch adjustment x (RRP – congestion price x constraint coefficient).* It is not clear how participants would bid given they are exposed to an unknown RRP at the time of bidding.

8 Clean Energy Council (CEC), Response to ESB's Consultation Paper, June 2022.

9 The total settlements for the two proposals are identical. In the Edify proposal a generator pays for congestion relief and gets an increased output at the RRP and in the ESB's CRM model the increased output is paid at the LMP. In an efficient market the market clearing congestion relief price would be RRP-LMP and this results in exactly the same total settlements as for the ESB's CRM.

1.3 Bidding assumptions

Participants face different bidding incentives in the energy market and the CRM.

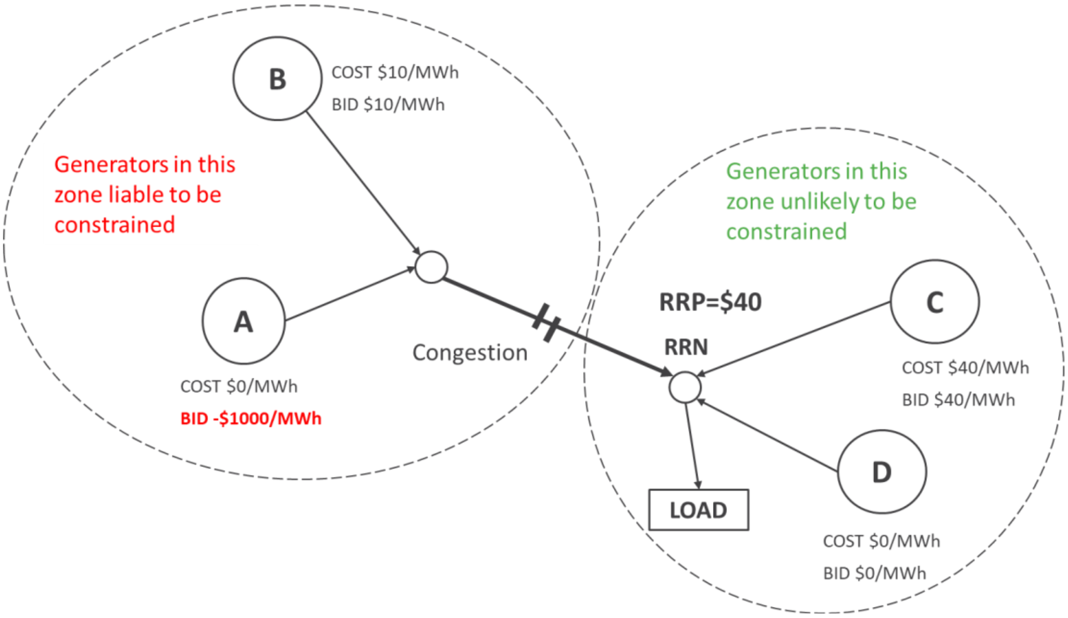
1.3.1 Bidding incentives in the energy market

The energy market provides incentives to constrained generators to bid to the market floor price, referred to as 'disorderly' bidding or 'race to the floor' bidding.

Constrained generators know that their offers will be unlikely to affect the RRP. The profit maximising behaviour of a generator is to bid at the market floor price of -$1,000/MWh, if their costs are lower than the forecast RRP. This maximises their individual dispatch quantity and profit.

Figure 2 shows two generators, A and B, in a constrained zone. Given their costs are less than the RRP, they would both profit from being dispatched. Generator A has bid at the market floor price. Generator B continues to bid at its cost of $10/MWh. Generator A will be dispatched before Generator B. All generators affected by the constraints are incentivised to maximise their share of the limited transmission capacity by engaging in this bidding behaviour: not racing to the floor when one's competitors are doing so reduces the generator's share of dispatch, and hence revenue. In future dispatch intervals, Generator B would maximise profits by bidding -$1,000/MWh to avoid being curtailed.

Figure 2 Bidding incentives in the energy market

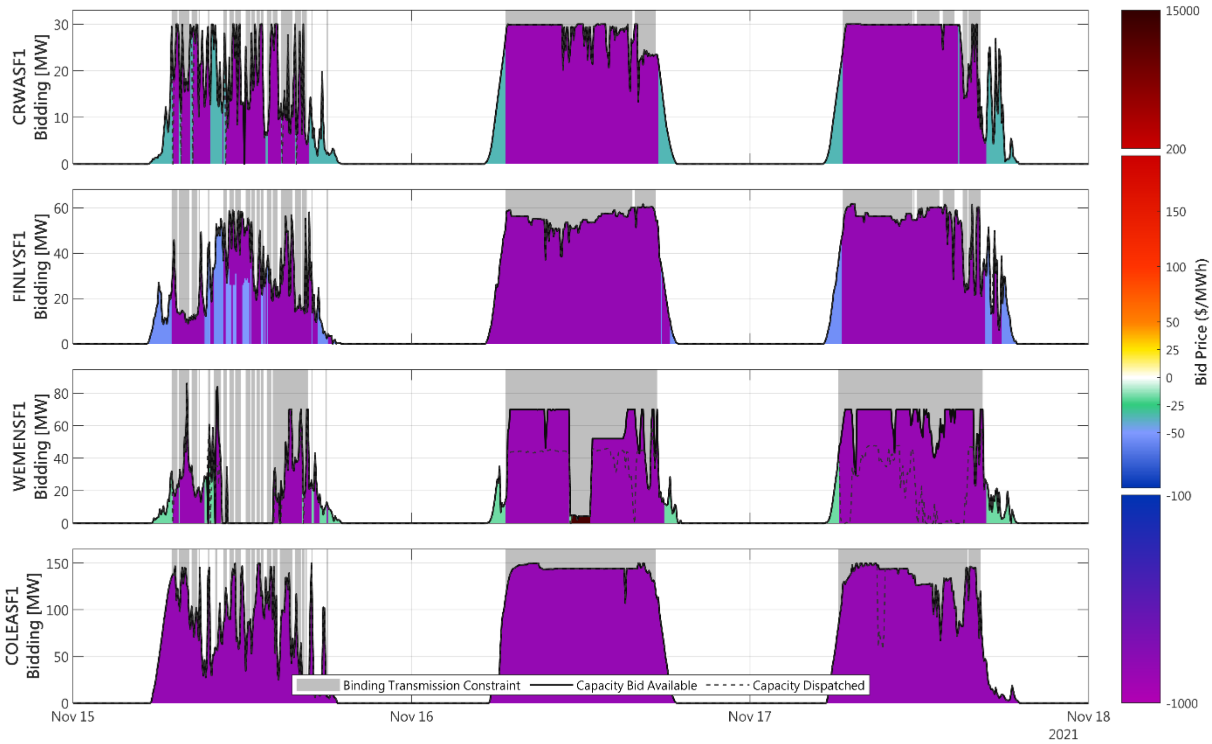


Source: ESB.

Analysis of NEM bids for four solar farms illustrates how this bidding behaviour materialises in practice (it is not just theoretical). Figure 3 overleaf shows a series of consecutive dispatch intervals in November 2021. Dispatch intervals affected by a binding transmission constraint have a background shading in grey. The coloured areas show the bidding changes in response to these constraints.

Three of the solar farms adjust their bidding behaviour from their marginal cost (between $0/MWh to -$55/MWh being the assumed opportunity cost of the price of LGCs). As the constraint binds, their bids fall towards the market floor price (pre-loss adjusted bids < -$800/MWh are marked in purple). The fourth solar farm is continually bidding towards the market floor price which is likely to reflect the opportunity cost based on its contractual terms.

Figure 3 Bidding at the market floor price in response to congestion



Source: Battery Storage and Grid Integration Program, 'State of Congestion Management in the National Electricity Market', The Australian National University, received 7 February 2023.

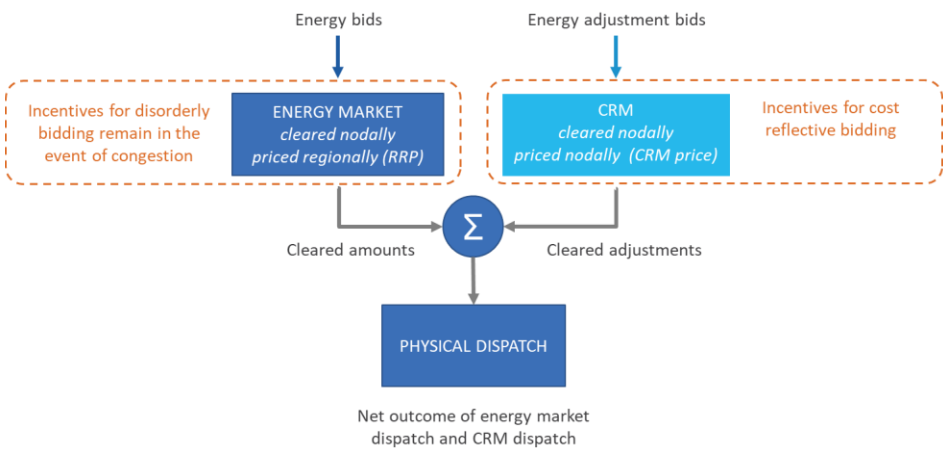
1.3.2 Bidding incentives in the CRM design

In the CRM design, the energy market dispatch continues to be priced at the RRP. Bidding incentives are consistent with today's energy market (i.e. constrained generators will pursue 'disorderly bidding').

Since CRM adjustments are settled at the nodal CRM price rather than RRP, the CRM does not incentivise disorderly bidding. Instead, participants are more likely to bid the value they put on their output, referred to as 'cost reflective' bidding. As with any market, participants will bid strategically in the CRM but the bids are expected to be closer to their marginal or opportunity costs.

Figure 4 visualises the bidding incentives for the two markets.

Figure 4 Bidding incentives in the CRM design



1.4 Modelling the CRM design

The ESB contracted NERA to perform a market modelling exercise to quantify and compare the operational and financial outcomes resulting from today's energy market and the CRM design.

1.4.1 Objectives

The purpose of the modelling was to:

- consider the impact of the reform design on bidding incentives faced by market participants
- model the impact of changed bidding behaviour on dispatch, pricing and settlement outcomes
- present the market outcomes for different groups of market participants.

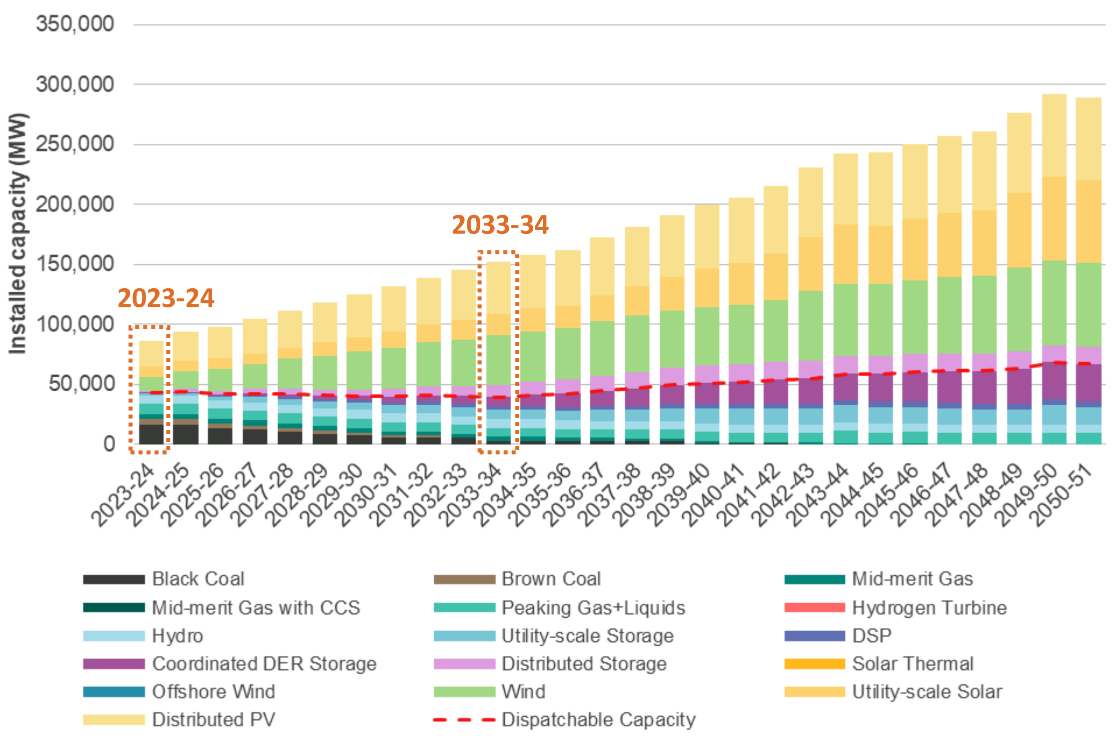
1.4.2 Modelling approach

A new model was developed in PLEXOS which represents the actual NEM transmission network and optimises dispatch in each interval by solving for the lowest cost dispatch which delivers secure power flows across the network. This approach allows the modelling to calculate the nodal prices across the grid and use those to construct the dispatch outcomes for the status quo and the proposed CRM.

Given the complexity of the task, the model was developed and run for two years, 2023-24 and 2033-34. For each year, the model generally adopts assumptions in the Integrated System Plan (ISP) 2022 and the outcomes from that plan including the forecast generation and storage capacity and recommended transmission augmentations.

2023-24 is not the planned date of reform implementation. It provides a baseline of results to analyse the impact of the model options on today's generation fleet and transmission network. Figure 5 shows the change in capacity mix for these two time periods.

Figure 5 Forecast NEM capacity to 2050, Step Change, Candidate Development Path 12



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12.

1.4.3 Scenarios

The modelling scenarios and sensitivities discussed in this paper include:

Scenarios

- Base case (status quo)
- CRM design[10]

Sensitivities

- CRM design with partial participation[11]
- CRM alternative design[12]

The CRM design reflects the preference of stakeholders and the ESB to calculate RRPs based on the energy market dispatch.

The CRM alternative design reflects the status of the design choices that were open when the NERA modelling was scoped. Insights from the sensitivity are included for stakeholders' information, and to enable readers to interpret the NERA detailed modelling report.

1.4.4 Bidding assumptions applied in the modelling

'Cost reflective' bidding and 'disorderly' bidding are critical characteristics that define the scenarios.[13]

Cost-reflective assumes that all generators bid their short-run marginal cost (SRMC) as an offer price. SRMC is determined in the PLEXOS modelling from input assumptions for the generator fuel and other variable (operating and maintenance) costs which are aligned with the assumptions of the ISP 2022. Disorderly bidding is not applied to all market participants; it is only applied to in-merit generators that are facing a binding constraint (i.e. those with costs less than the RRP).[14] Section 2.2 explains the model limitations for hydro and storage.

Table 1 outlines the bidding assumptions.

Table 1 Bidding assumptions as modelled for the energy market and the CRM

	Bid assumptions for…	
Technology	**Energy market**	**CRM**
Variable renewables	Disorderly	Cost-reflective
Thermal	Disorderly	Cost-reflective
Hydro	Cost-reflective	Cost-reflective
Storage	Cost-reflective	Cost-reflective

10 CRM design assumes that RRP continues to be calculated based on the energy market dispatch. This was referred to as 'Option 1' in the Directions Paper (section 4.2.5.).

11 CRM design with partial participation assumes that participants with the highest opportunity for profit increase in the CRM will opt in and participants with lower CRM profits will choose not to participate.

12 CRM alternative design assumes that RRP is calculated based on the CRM dispatch (RRP_{CRM}). This was referred to as 'Option 2' in the Directions Paper.

13 In NERA's detailed report, cost reflective bidding is also referred to as marginal cost bidding (MCB) and disorderly bidding is also referred to as race-to-floor (RTF) bidding.

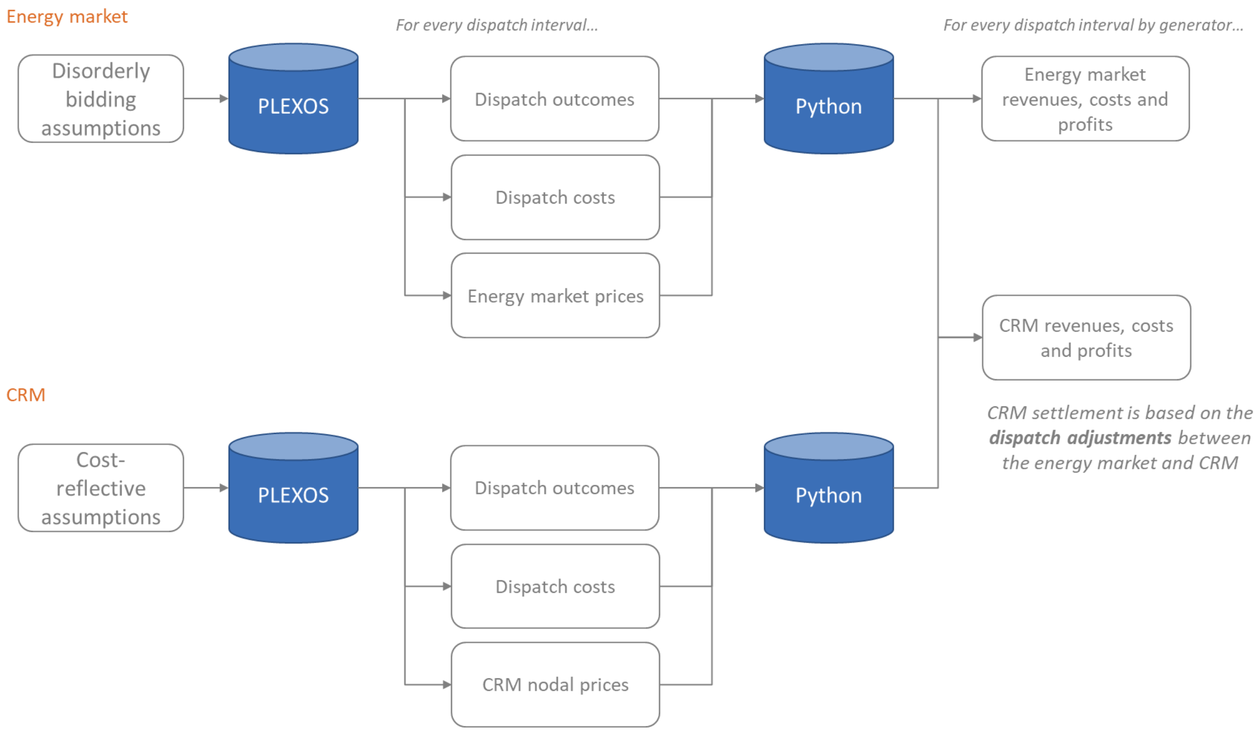
14 The following rules are applied to identify generators with incentives to bid disorderly. For each generator at each dispatch interval; SRMC < RRP, by more than $1/MWh; and LMP < RRP, by more than $1/MWh.

PLEXOS selects the cost-minimising dispatch for each dispatch interval based on the bids. Figure 6 illustrates the modelling process to determine dispatch and financial outcomes.

In the base case, financial outcomes are based on the energy market revenues, costs and profits only.

In the CRM scenario, financial outcomes are based on a combination of the energy market and CRM revenues, costs and profits. If a scheduled resource does not participate in the CRM, its CRM revenues, costs and profits will be nil.

Figure 6 Process diagram for PLEXOS and post-processing in Python



Source: ESB.

The figure aligns to the sequence of the energy market dispatch (first) and the CRM (second). For modelling practicalities, NERA first runs a dispatch based on cost-reflective bids to identify which generators are likely to bid at the market price floor (in-merit and likely to be constrained-off). This data is used to create a revised set of disorderly bids for the energy market.

2 Key concepts

This chapter outlines key concepts that will help readers to engage and interpret the key findings in this report. It includes:

- the forms of CRM trades based on the different network configurations
- the limitations of the modelling including planned limitations (simplifications applied upfront to the model assumptions) and unexpected issues (identified during the course of modelling).

2.1 Forms of CRM trading

2.1.1 Overview

The rationale of the CRM design is that, whilst regional pricing induces disorderly bidding, nodal pricing induces cost-reflective bidding. This allows the inefficient dispatch caused by regional pricing – whether in today's market or in the "energy dispatch" of the CRM design – to be "unwound" by efficient dispatch in the CRM. CRM *trading* is defined to be the difference between the two dispatches. Because disorderly bidding is associated with congestion, CRM trading is always associated with some congestion arising in the energy dispatch.

CRM buyers include generators whose output is reduced in the CRM or scheduled load whose consumption is increased. This allows other constrained generation to increase its output, without overloading the constraint. So long as the cost of the former is higher than the cost of the latter (and this is guaranteed when CRM bids are cost-reflective), dispatch costs are reduced.

The amount of CRM trading depends upon the size and topology of the constraint and the types of generation and load associated with the constraint. Four topologies are described with a CRM trading scenario applied to each type:

- radial constraint
- intra-regional loop
- inter-regional loop
- inter-regional radial.

Appendix C provides a one-page reference for the network topology types introduced in this chapter.

2.1.2 Radial constraint

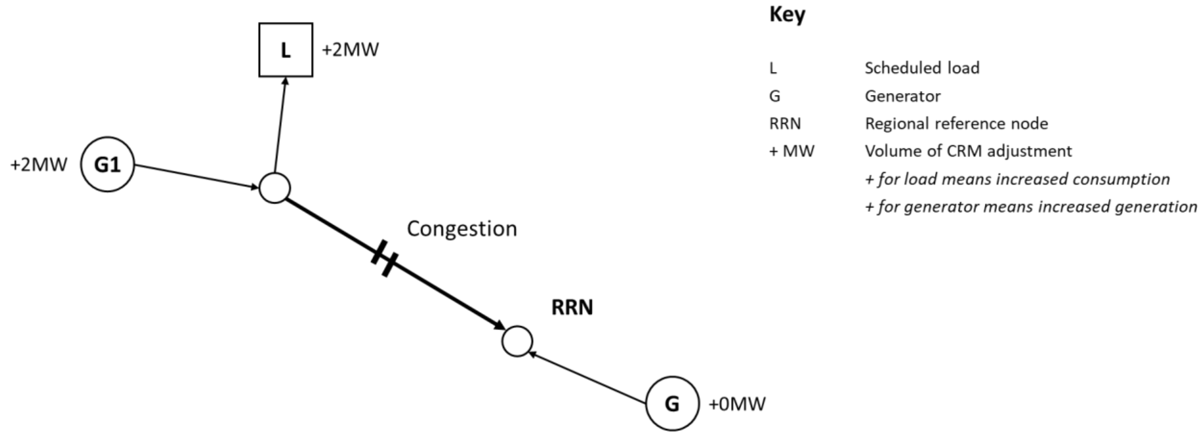
The radial constraint is the easiest type of congestion to understand. As a result, this topology exerts a strong influence on stakeholder expectations for CRM outcomes.

Under the CRM, there is the opportunity for trading to occur between generation and scheduled load (typically storage) located behind the constraint. The scheduled load can charge and buy energy from a variable renewable energy (VRE) generator, allowing it to increase output. Conceptually the VRE generator is selling cheap power to the scheduled load that would otherwise be curtailed.

CRM trading could also occur between two generators with different costs located behind the constraint. Such a scenario would be less likely in the future energy mix where VRE generators have similar costs (depending on contractual arrangements but typically zero or the opportunity cost of LGCs).

Because it is a radial constraint and the generation and load adjustments are of *equal* quantities, there is no impact on dispatch beyond the constrained zone. This is a topology where the original Edify Energy proposal – of local congestion relief markets behind each constraint – operates well.

Figure 7 Simple radial constraint



Source: ESB.

Figure 7 illustrates the topology of a simple radial constraint. It shows two parties behind a constraint; scheduled load (L) and a VRE generator shown as a single generator (G1). Congestion is caused by G1 behind the constraint.

For clarity, the figure only shows CRM trades and does not show energy dispatch outcomes and prices. In the CRM, L increases its consumption by 2MW and G1 increases its generation by 2MW. A likely scenario is that the RRP is modest, meaning that the scheduled load does not want to charge or discharge in the energy dispatch.

The traded CRM price is not shown but it will reflect the bids and offers the constrained parties submit to the CRM. Most likely, the two parties would share the difference between the value of the electricity for L and the cost (zero) of generating it for G1.

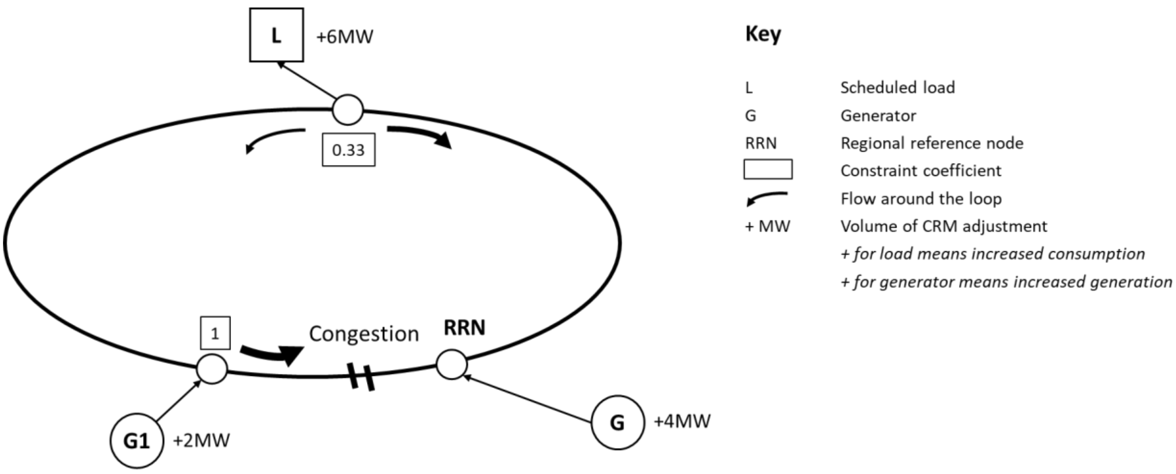
2.1.3 Intra-regional looped constraint

A more complex, and far more common, topology is the loop-flow constraint, shown in Figure 8 below. This was the topology applied in the ESB's worked examples of the CRM design in the Directions Paper.[15]

It is *intra*-regional because no interconnectors participate in the constraint, only scheduled load and generation within a single region. The scenario is otherwise similar: the RRP is such that the scheduled load is not dispatched in the energy dispatch but can buy cheap power in the CRM from the VRE generators that would otherwise be curtailed.

15 https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf November 2022.

Figure 8 Intra-regional loop-flow constraint



Source: ESB.

In the previous example of the radial constraint, the coefficients on the left-hand side (LHS) of the constraint were all equal (to unity) and hence the CRM trades are one-for-one with energy. In the example of the loop flow, coefficients vary depending on how far around the loop the relevant load is situated from the point of congestion.

In Figure 8, the coefficients are shown in boxes at each node. By definition, the local RRN always has a zero coefficient and so this is not shown. G1 has 3 times the coefficient of the scheduled load meaning that, to avoid overloading the constraint, the scheduled load in the CRM has to be three times the incremental VRE output. These two parties no longer offset each other in MW terms. The generator at the RRN must also sell into the CRM to balance demand and generation across the system.

Trading outcomes become more complex now, with CRM prices likely to be different at each of the three nodes. Nevertheless, the CRM trades will be profitable for those involved and lead to an overall reduction in dispatch costs: taking account of the value of the additional scheduled load. It is profitable because each buyer has bought energy at a price lower than or equal to its bid, and each seller has sold a price higher than or equal to their bid, or else the trades would not have cleared.

This topology shows that it will be necessary – and also profitable – for RRN generators (or, more generally, any generator not participating in any binding constraint) to opt in to trade in the CRM.

In general, the level of involvement of the RRN generator in the CRM trade will depend upon the *differences* in coefficients of those CRM traders participating in the constraint. The previous simple radial constraint example was a special case where there are no differences and hence no RRN involvement.

2.1.4 Inter-regional looped constraint

The inter-regional looped constraint involves participation by one or more interconnectors in the constraint. There are two types considered here:

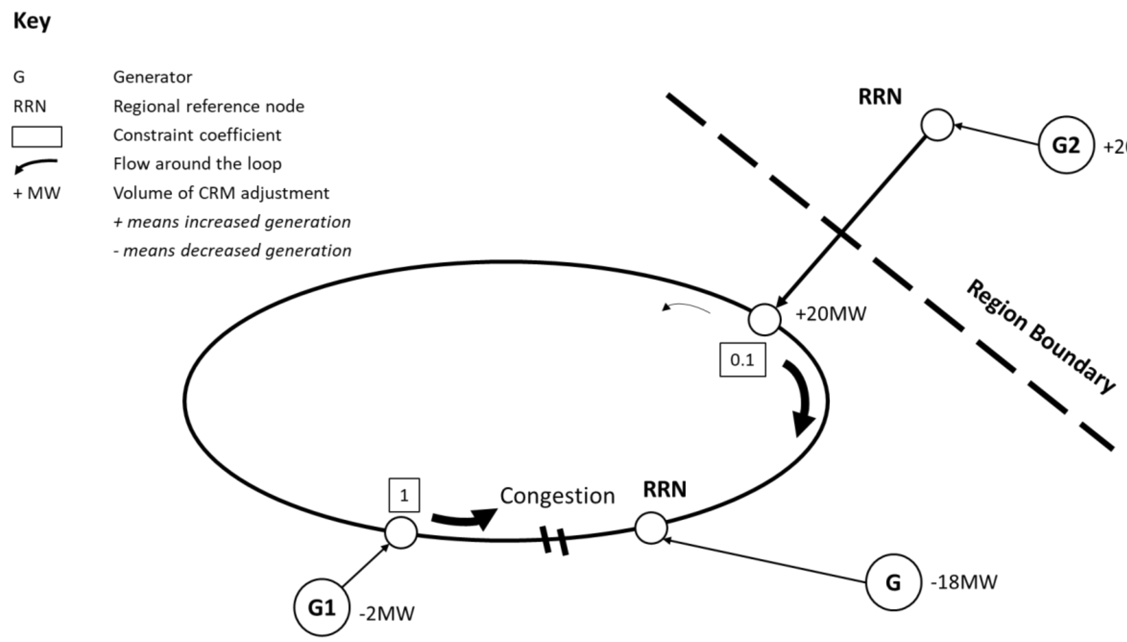
- ‘Hybrid’ involves interconnector and generation participation and leads to interesting CRM trading outcomes.
- ‘Pure’ is limited to interconnectors and would not lead to CRM trading.

Hybrid inter-regional looped constraint

This type is referred to as "inter-regional" because one or more interconnectors participate in the constraint and "hybrid" because there is also generator participation.

Based on the constraint formulation in NEMDE, the interconnector appears like a generator with its own coefficient. Figure 9 shows a simple example where there is a single interconnector and generator participating; the scheduled load is now omitted as it is no longer required for CRM trading to occur. The interconnector has a coefficient of 0.1. For simplicity, the interconnector itself is radial (a single line crosses the region boundary) but hybrid inter-regional constraints may also arise on looped interconnectors that have multiple paths between the two regions.

Figure 9 Hybrid inter-regional constraint



Source: ESB

G2 has higher costs than G. G1 has the lowest cost as a VRE generator but has the highest contribution to congestion.

In the energy market:

- G1 is behind the constraint and will bid at the market floor price
- G will bid at or around cost near the RRN
- G2 will bid at or around cost at the remote RRN.

Despite having the lowest cost, G1 causes an inefficiently *high* output in the energy dispatch because the balancing energy is provided by G rather than G2.

In the CRM, this inefficiency is unwound with CRM adjustments shown in Figure 9:

- G2's output increases by 20MW
- G and G1's outputs decrease by -18MW and -2MW respectively.

Just as with the intra-regional case, the ratio of these changes must reflect the ratio of the coefficients so that the flow on the congested line remains unchanged. In this case, the factor is 10, and a reduction in G1's output by 2MW is offset by an increase in the interconnector flow of 20MW.

This affects generators at both RRNs, as their outputs must increase or decrease to retain the energy balance in each region. The extra 20MW of exports from the remote region means that the RRN generator (G2) must increase its output commensurately. The extra 20MW of imports into the local region, partially offset by the decreased output of the VRE generator (G1), means the generator at the local RRN (G) must decrease its output by 18MW.

The ratio in the coefficients creates a *gearing* effect, with a multiplier of 10 in this case, whereby each 1MW change in the VRE generator's output creates a much higher change in generation at the two RRNs. The highest possible multiplier is 14 (i.e. where the VRE generator's coefficient is 1 and the interconnector coefficient is 0.07).[16] Once the interconnector coefficient drops below this level, AEMO excludes it from the constraint, which then becomes intra-regional.

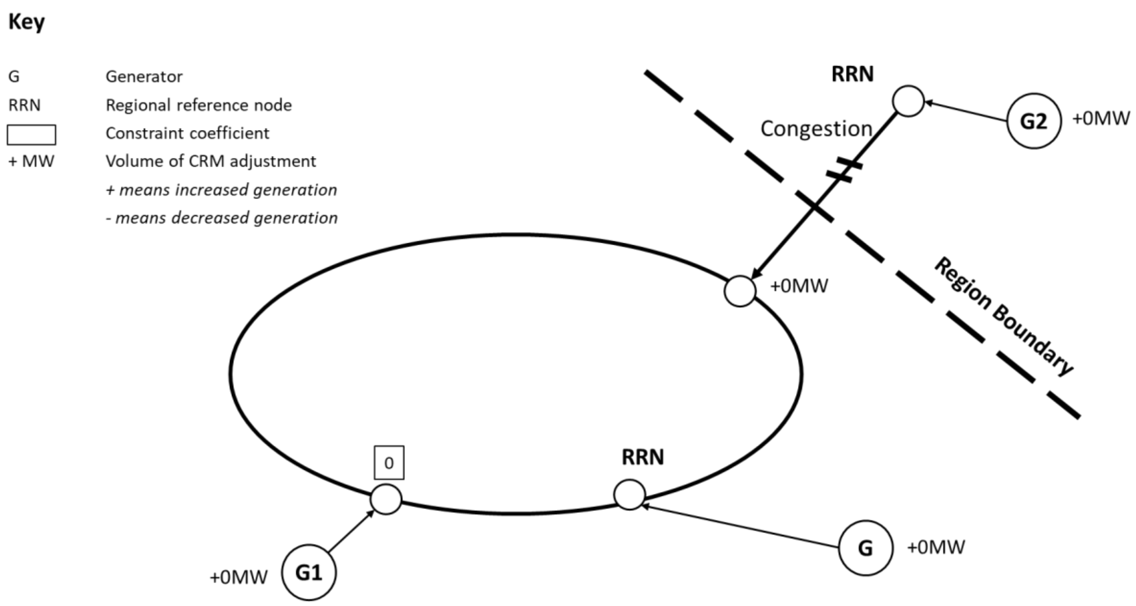
A side effect of this gearing is that it can impact RRPs. In this example, an RRP change is unlikely because it only relates to a 20MW change in RRN generation. In real-world scenarios, there could be larger MW changes with corresponding RRP impacts. These impacts will not materialise directly in the NEM settlement given the RRP will be based on the energy market dispatch. They may appear indirectly, as generators adopt bidding strategies which reflect these dynamics.

Pure inter-regional looped constraint

The pure inter-regional constraint has interconnector participation but no generator participation.

In Figure 10, G1 now has a coefficient of zero meaning no participation in the binding constraint (G1 was constrained in the previous examples). This would typically involve congestion on a line crossing – or very close to – the regional boundary, but only where there is a single transmission path crossing the boundary (or the influence on line flows of a second path is insufficient to cause AEMO to incorporate it in the constraint formulation).

Figure 10 Pure inter-regional constraint (no generator participation)



Source: ESB.

16 According to AEMO's Constraint Formulation Guidelines, the absolute value of the factors on the LHS of constraint equations must be greater than or equal to 0.07. Participants with factors lower than 0.07, are moved to the right hand side (RHS) by subtracting the term from both sides. These participants and any relevant non-scheduled generators are then taken into account in the network loading but their impact is not optimised through dispatch.

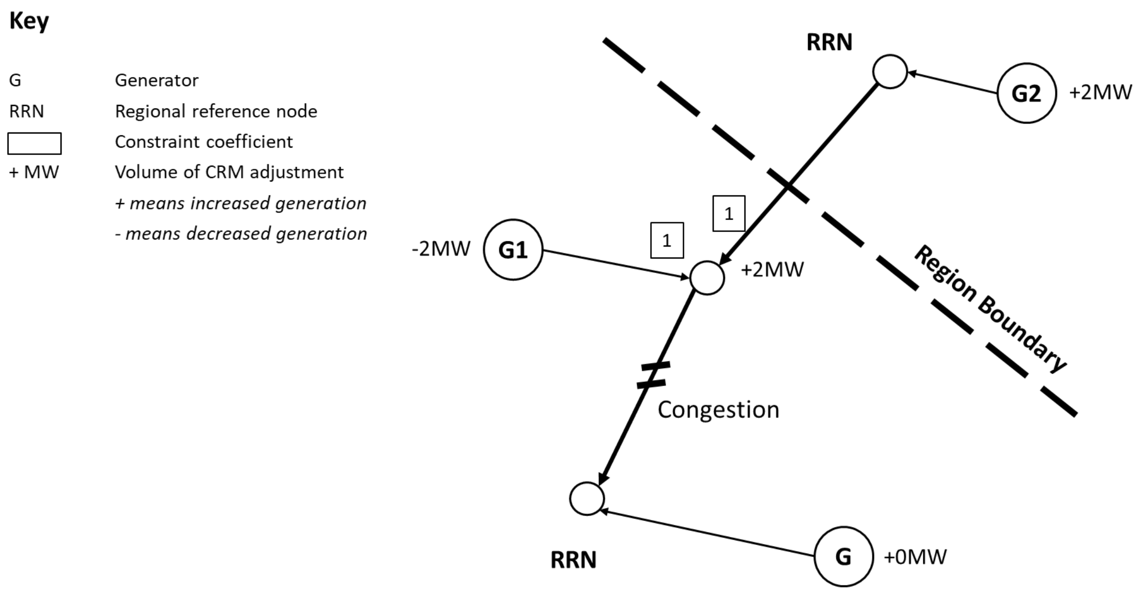
Because pure inter-regional congestion is priced correctly in the current NEM design, the introduction of the CRM design will have no impact on market outcomes. There will be no CRM trading around a pure inter-regional constraint. Figure 10 showed there were no CRM MW adjustments.

Because pure inter-regional congestion is priced correctly in the current NEM design, the introduction of the CRM design will have no impact on market outcomes. There will be no CRM trading around a pure inter-regional constraint. Figure 10 shows there are no CRM MW adjustments.

2.1.5 Inter-regional radial constraint

Figure 11 shows another special case of a hybrid constraint where the constraint is *radial*. Both interconnector and generators have a coefficient of unity. There can still be CRM trading but there will be no gearing effect. The CRM trade is now between the constrained generator (G1) and a generator at the remote RRN (G2).

Figure 11 Hybrid inter-regional radial constraint



Source: ESB.

2.1.6 Applying the network topologies to the CRM design and modelling

The initial CRM proposed by Edify Energy was predicated on the concept of a radial constraint. The CRM models developed by the CEC and ESB were more generalised for the NEM's network and predicated on the intra-regional loop flow constraint. This allows the CRM design to handle the impacts on RRN generators. But the NERA modelling results suggest that CRM trading – and its materiality in terms of increasing dispatch efficiency and generator profitability – is dominated by *inter*-regional congestion. With the benefit of hindsight, this is perhaps self-evident as:

- Trading behind an intra-regional constraint relies on a scheduled load participating, and this is currently the exception rather than the rule. (Or alternatively, generators with different costs but this may become increasingly rare if congestion associated with REZs comes to dominate dispatch where VRE generators share similar marginal and opportunity costs.)
- Trading on a looped constraint can create a gearing effect which multiplies the impact on dispatch outcomes and can affect more than one region.

The next chapter 2 discusses CRM outcomes, as modelled by NERA, which are dominated by:

- 2023-24 congestion in south-west NSW
- 2033-34 congestion in northern NSW.

Both of these constraints have an inter-regional topology.

2.2 Model limitations

2.2.1 Overview

NERA has developed the PLEXOS model to forecast dispatch outcomes (quantities, costs and prices) for future years assuming different scenarios (status quo market design and access reform options). These dispatch outcomes are inputs to NERA's settlement models, which then estimate the impacts of access reform on generator revenues and profits, and customer prices.

This is an extremely difficult task. It involved modelling both short-term inputs such as generator offers and aligning the model with the ISP's long-term outputs such as generator entry and exit and transmission development.

To make the task tractable, NERA adopted some simplifications in its modelling assumptions and methodology, referred to below as "planned limitations". Further difficulties arose whilst operating the model, referred to as "unexpected issues". Both types affect the model outcomes and cause them to diverge – in known or unknown ways – from outcomes that we would reasonably expect, given our knowledge of actual operational and investment dynamics in the NEM.

This section explains these issues and provides guidance as to how they might affect model outcomes; or, conversely, how the reported results should be interpreted.

2.2.2 Planned limitations

No strategic bidding

The cost-reflective approach was chosen for two reasons:

- Under conditions of perfect competition, the payment of the nodal CRM price at the margin should incentivise generators to bid at cost into the CRM dispatch.
- Accepting the fact that competition will be imperfect, it is very difficult and contentious to model bidding strategies of generators that have pricing power.

The choice of the cost-reflective approach for CRM operations has two implications for the results:

- In the modelling, generators behind constraints are not using their pricing power to optimise CRM outcomes. In real world scenarios, generators could strategically trade off higher CRM profits for lower trading volumes. The modelled efficiency gains could be greater than reality.
- The RRP modelled for the CRM sensitivity (based on the CRM dispatch) is likely to substantially under-estimate the actual RRP under similar conditions. This is most notable during peak conditions, or times when the maximum amount of dispatchable generation is required where strategic bidding impacts the most on RRP outcomes.

No clamping

Counter-price flows occur when electricity flows from a higher-priced region to a lower-priced region. In today's market design, counter-price flows may or may not be efficient depending upon the costs of the actual generators causing that flow. In any case, it causes problems when generators are paid a regional rather than local price, delivering high residues which need to be recovered from customers via transmission charges.

To avoid these situations, AEMO clamps counter-price flows on interconnectors once they generate material negative residues aggregated over time. Simulating AEMO's operational procedure to clamp interconnectors would add complexity to the modelling and potentially instability to PLEXOS by having an intermittent constraint and one that needs to aggregate across dispatch intervals.

Furthermore, post-2025 when Project Energy Connect (PEC) is commissioned, the loop of interconnectors between NSW, Vic and SA makes the negative residue management task more complicated. AEMO is considering its policy options and has released a consultation paper.[17]

In today's energy market, clamping could lead to more or less efficient outcomes:

- Clamping could intervene to prevent a dispatch interval with disorderly bidding and high costs, or
- It could prevent a dispatch interval achieving the lowest costs because it is clamping interconnector flows which would be efficient and reduce overall costs.

In the CRM design, clamping may still be required in the energy market dispatch but there is potential it is not required in the CRM. As a general principle, participants would have no incentives to create counter price flows when they are paid a nodal CRM price.

Unfortunately, the level and materiality of modelled counter-price interconnector flows in 2023 and 2033 were higher than expected. It is not possible to estimate the impact of clamping with any accuracy.

Simplistic disorderly bidding

The NERA approach to disorderly bidding was adopted because it is simple, objective and a reasonable approximation to actual disorderly bidding. However, it has the limitation that the decision to bid at the market floor price is based on congestion in the cost-reflective dispatch whereas, in reality, it is based on congestion in the actual disorderly dispatch. In practice, disorderly bidding may "feed on itself", creating additional congestion that creates additional market floor bidding that creates more congestion and so on. This is impossible to model without making many subjective assumptions about bidding behaviours, and it is unknown the extent that the impact of disorderly bidding is underestimated as a result.

Using the ISP expansion plan

This was chosen as an objective and broadly-accepted scenario to use in the modelling. However, the ISP is based on a co-optimised expansion of generation and transmission which could only possibly occur (even approximately) where access reform has been implemented. It is the inefficient expansion driven by the status quo market design that is a primary reason for introducing access reform.

This has two implications:

- The modelling is not designed to show the capital efficiencies that would arise from access reform. This relates to the components of the transmission access reform model addressing investment timeframes and is not part of this scope of work.
- In practice, without the co-optimisation of generation and transmission, there is likely to be more congestion and greater opportunity for disorderly bidding in 2033-34. Operational efficiencies from the CRM design may be understated.

17 AEMO, Project Energy Connect Implementation Paper, available at https://aemo.com.au/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper, released 15 November 2022.

Applying the ISP expansion plan

The ISP forecasts generator entry by REZ and does not forecast the exact entry location within each REZ. NERA had to develop and apply a methodology since PLEXOS requires generation to be defined at the nodal level. NERA elected to add new generation at nodes where there is already existing generation. This is not unreasonable in itself, but can give rise to non-credible outcomes (e.g. extreme congestion in the locality which can cause solve problems for PLEXOS).

Even if the planting were more realistically spread throughout the REZ, pinch points will arise which would be unlikely in practice or, if they did arise, local remedial actions might be taken (e.g. runback schemes). This methodology can create unrealistic problems of local congestion which can impact the overall results. It seems likely that the 2033 results are substantially impacted by local congestion created in the New England REZ.

No priority access scenario

It was not possible to model a scenario with priority access. In the Directions Paper, the ESB proposed an access model based on the CRM design with two variants; congestion fees or priority access. Only the variant for priority access would affect energy market outcomes and would be eligible for modelling changes to dispatch, pricing and settlement outcomes in the energy market and CRM.

The priority access involves allocating queue numbers to incumbents and new connecting generators which are classified into tiers for the purposes of dispatch. Generators with a favourable queue number are prioritised in the energy market dispatch when their bids are tied at the market price floor. Priority access would not apply in the CRM. There are a number of outstanding design choices including, not exclusively, the definition of tiers, the approach to grandfathering, the allocation of priority quantities to resources and duration of priority access rights.

It was difficult to integrate the priority access scenario into the PLEXOS framework, even with highly simplified assumptions. In the model, new generator capacity is represented as an increase in capacity of an existing generator at the same location. It was not possible to easily distinguish between existing and new generators.

If the priority access scenario had been implemented, it is expected:

- There would have been limited impact on the 2023-24 results, assuming there is limited generation entry over the next calendar year relative to current hosting capacity and incumbents are fully grandfathered in the priority access design.
- Priority access could create inefficiencies in the energy dispatch compared to today’s energy market. This would increase the efficiency gain and profits available in the CRM.
- Priority access would re-distribute the profits available in the CRM between participants (depending on their priority level).

2.2.3 Unexpected issues

No disorderly bidding on energy-constrained plant

In the NEM, energy-constrained generators (hydro and storage) will submit offer prices which reflect their “true SRMC” being the sum of their directing operating costs (e.g. wear and tear on turbines or batteries) and their opportunity costs (e.g. using their stored energy now rather than at a later time). This true SRMC will drive their disorderly bidding. For example, if Snowy Hydro calculates its true SRMC to be $300/MWh, it may bid the market price floor only when it is constrained off *and* RRP is greater than $300/MWh.

The PLEXOS algorithm does not explicitly offer energy-constrained plant into dispatch in this way. Instead, they optimise energy use over longer timeframes and apply intermediate quantity constraints to ration its use in dispatch. Thus, there is no obvious “true SRMC” to identify the trigger for disorderly bidding. Given this difficulty, disorderly bidding of energy-constrained plant was not attempted.

Long solve times

NERA applied a highly granular modelling methodology under which every node and line in the NEM is modelled and dispatch is undertaken for each half-hour in the year. This is more granular than the models that AEMO uses in its ISP development. It has led to very long solve times for PLEXOS (10-20 hours for each run with around six runs required for all scenarios and sensitivities).

An initial objective of modelling every year in the ISP period (e.g. from 2023 to 2040) was substantially scaled back to modelling just two years: 2023-24 and 2033-34 (shortened to 2023 and 2033). The results reflect the particular congestion that would arise in those years, e.g. major congestion occurring in SW NSW in the 2023 results might be substantially mitigated by Project Energy Connect (PEC) in 2026, or by Victoria – New South Wales Interconnector (VNI) West in 2031.[18]

Phantom congestion

For each modelled dispatch interval, PLEXOS reports nodal prices at each node and congestion prices on each line. A non-zero congestion price implies congestion on this node, which then gives rise to a pattern of nodal prices known as a “spring washer” around network loops containing that congested line. There is a strict mathematical relationship between congestion prices and nodal prices.

In dispatch intervals where there is no reported congestion (all network constraint congestion prices are zero), nodal prices should be the same at every node.[19] This mathematical relationship sometimes broke down in the PLEXOS outputs. The modelling shows instances of congestion that are not reflected in the congestion prices; we refer to this as “phantom congestion”. The cause of this issue is unknown.

This led to immediate difficulties for CMM settlement, given that this uses both congestion prices and nodal prices. Where these are inconsistent, this gave rise to anomalous results, which NERA took steps to resolve as described in their report.

The bigger problem is that phantom congestion is very difficult to analyse and explain, given that the exact location of the congestion is unknown and can, at best, be inferred by examining the pattern of nodal prices.

This problem is relatively minor in the 2023 results, and confined to the fringes of the NEM, such as far north Queensland. In the 2033 results, it is frequent and widespread. In particular, the counter-price flows on QNI in the disorderly dispatch outcomes, which are the primary driver of dispatch inefficiency, seem to be fully associated with phantom congestion. As a result, there is some confidence placed in the 2023 results but our key findings for 2033 focus on qualitative, rather than quantitative, insights.

18 Refer to AEMO (30 June 2022), 2022 Integrated System Plan – Appendix 5: Network Investments for the expected implementation timing of ISP projects.

19 Note that NERA has not modelled transmission losses.

Failure to solve

As with any dispatch algorithm, PLEXOS allows constraints to be violated when no feasible dispatch can be found. Some of these violations can be seen when PLEXOS reports curtailed load and RRPs at the market price cap. Because PLEXOS uses daily solve periods to schedule hydro and storage, this infeasibility sometimes arises for entire days, possibly consecutive ones. This is primarily a problem for 2033 and is discussed in the NERA report. One driver may be that PLEXOS finds it difficult to effectively model deep storage such as Snowy 2.0.

NERA has sensibly excluded these periods of infeasibility from their results. However, these are unfortunately the periods that could be the most likely to lead to major disruptive events in the absence of reform. For example, if the removal of disorderly bidding incentives could lead to a significant reduction in unserved energy (load shedding), this would be a substantial benefit of the access reform. However, if these periods of load shedding are excluded from the results, this benefit is not estimated or reported.

Furthermore, these constraint violations may arise not because there is no feasible dispatch for the period, but because PLEXOS can't *find* one; or perhaps cannot reschedule deep storage effectively so that the generation shortfall in that period can be addressed without creating another period of shortfall somewhere else.

3 Key findings

Given the model limitations, it is difficult to be confident in the quantitative results presented by NERA, particularly in 2033. Even if the results were accurate, they would only present a single scenario in two chosen years. Uncertainty remains around extrapolating these results to other scenarios and other years.

Nevertheless, the NERA modelling is valuable to provide insights as to how the CRM might operate in practice and broad trends as to how CRM outcomes may evolve through the energy transition.

The key findings are:

- Congestion arises mainly near regional boundaries and affects interconnectors flows.
- Disorderly bidding will cause substantial counter-price flows on interconnectors and associated settlement deficits if these flows are not clamped.
- CRM trading by unconstrained generators dominates trading by constrained generators because of the gearing effect on looped constraints.
- The CRM will lead to a significant reduction in the dispatch costs.
- The efficiency gain associated with lower dispatch costs is shared between generators and customers through an “efficiency dividend”.
- All CRM participants will receive an efficiency dividend; market participants who do not participate will not.
- The CRM design means that wealth transfers associated with changes to RRPs or access quantities are largely avoided.
- The CRM still provides efficiency gains and dividends even if there is substantial non-participation, although these gains are reduced.
- There are limited insights regarding the RRP outcomes given the model caveats.
- The modelling cannot show operational and capital efficiencies of access reform for batteries when the ISP is adopted as the starting point.

3.1 Congestion occurs mainly near regional boundaries

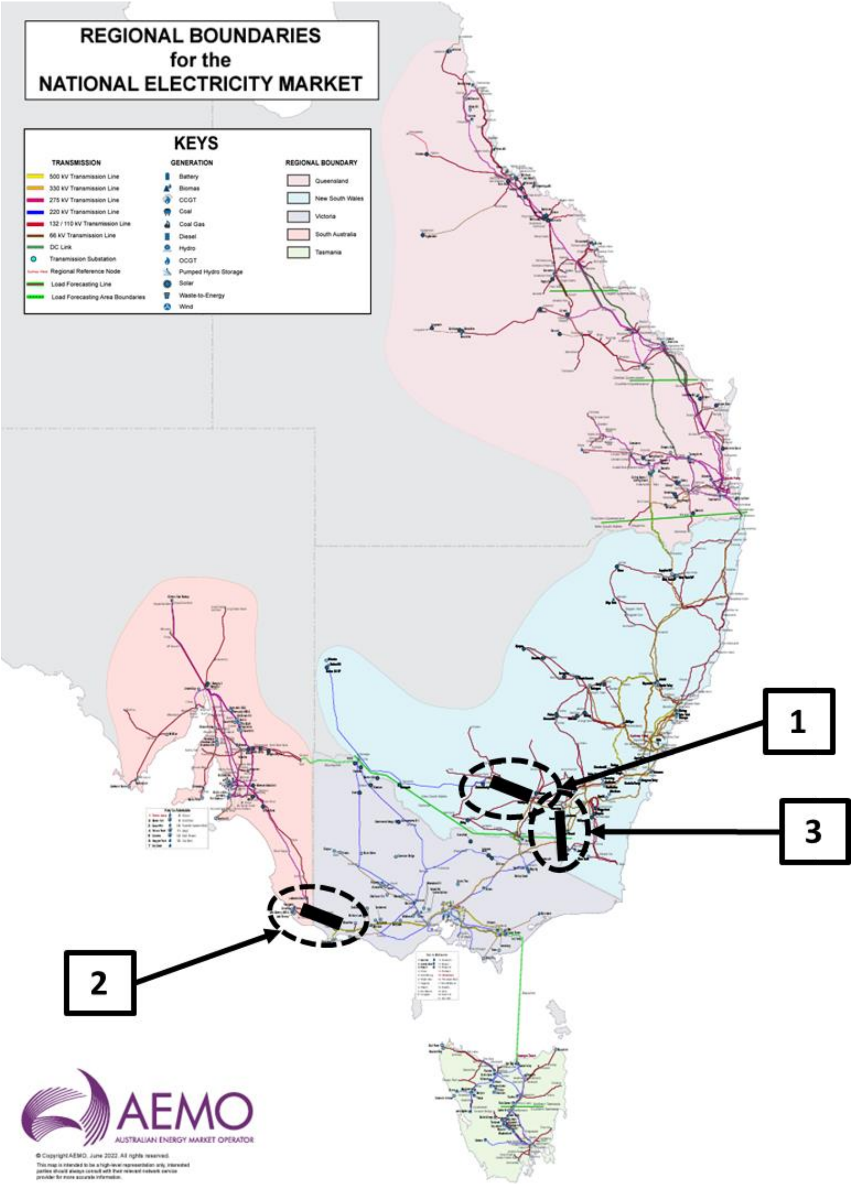
NERA lists the lines that are most congested in the 2023 and 2033 modelled results. The figures and tables below highlight the most significant congested lines.[20]

As discussed in section 2.1.4, CRM outcomes are very different depending upon whether the inter-regional congestion is “pure” (involving only interconnectors) or “hybrid” (involving interconnectors and generators). The CRM has no impact on the former but substantial impacts on the latter.

The biggest impact of disorderly bidding – and the biggest opportunity for CRM trading to unwind this inefficiency – arises on hybrid inter-regional constraints with a high level of gearing. These are the points of congestion to focus on when interpreting and understanding the NERA results.

20 The ‘most significant’ congested lines were determined by identifying where there is congestion for more than 1000 dispatch intervals (i.e. > 500 hours).

Figure 12 Lines with most significant forecast congestion, 2023



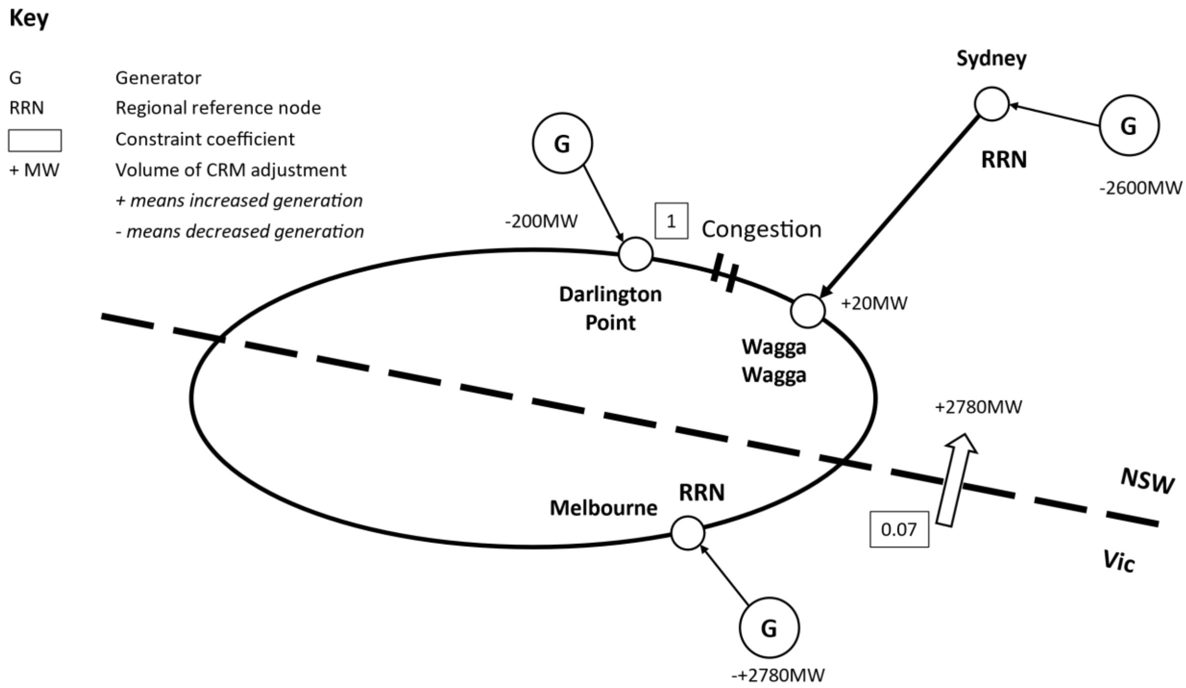
Source: ESB analysis of NERA outputs, AEMO [Map of regional boundaries in the NEM]

Table 2 Lines with most significant forecast congestion, 2023

Ref	From-to	Direction	Type
1	Darlington Point – Wagga Wagga	East	Hybrid inter-regional
2	Heywood – South East	Both	Pure inter-regional
3	Murray – Tumut	North	Pure inter-regional

In 2023, the only major congestion on a hybrid inter-regional constraint is on the Darlington Pt – Wagga line. This involves the Vic-NSW interconnector, which is highly geared.[21] This is the biggest driver of differences (and CRM-related efficiency gains) between the disorderly dispatch and cost-reflective dispatch in 2023. Figure 13 shows a stylised topology for this constraint and indicative CRM trading outcomes.

Figure 13 South-west NSW 2023 congestion – snapshot of a dispatch interval with congestion

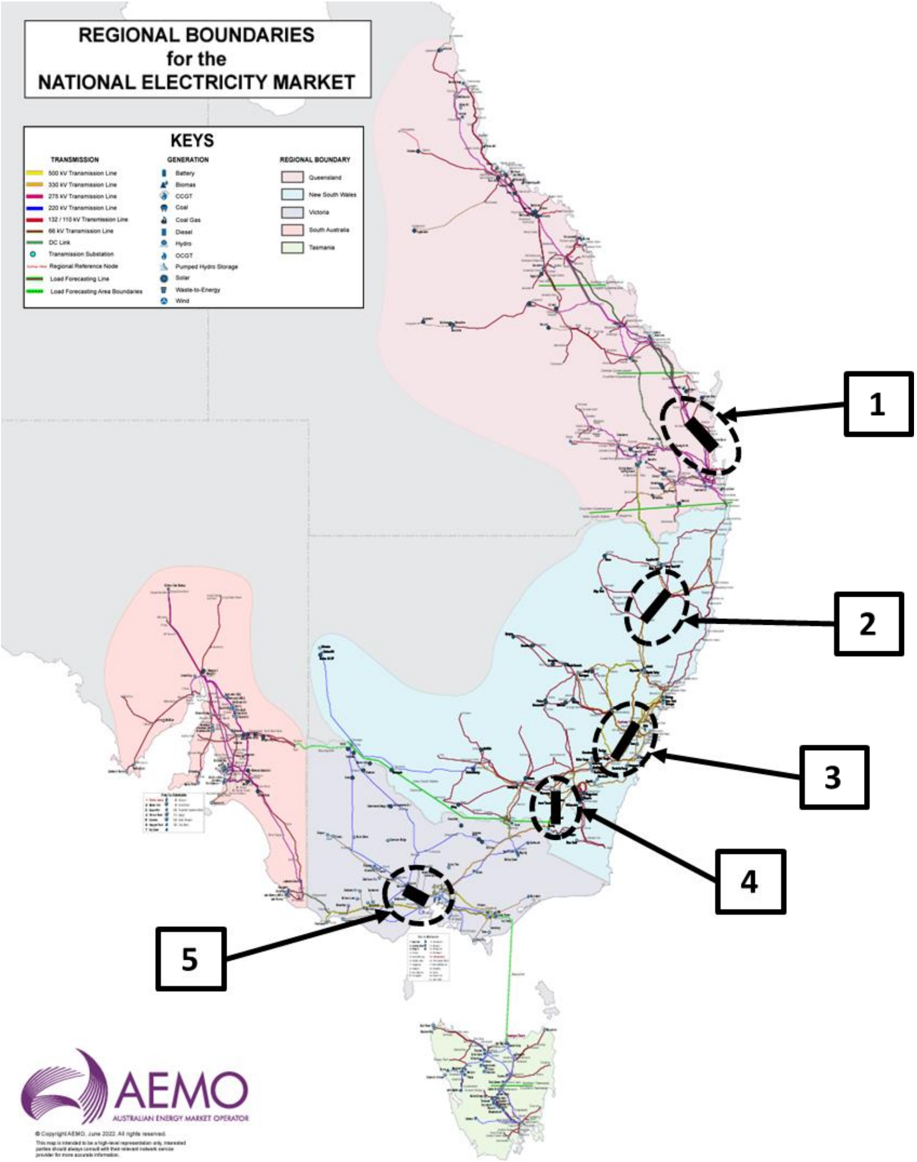


Source: ESB.

The diagram is a simple stylisation. Dispatch decreases of -2600MW for G represents reduced coal generation from NSW but also reduced flowthrough of inter-regional flows from QLD. Dispatch increases for G in VIC represents increased renewables and coal generation in VIC, but also inter-regional flows of renewable generation from SA and TAS.

21 Gearing is discussed in section 2.1.4.

Figure 14 Lines with most significant forecast congestion, 2033



Source: ESB analysis of NERA outputs, AEMO [Map of regional boundaries in the NEM]

Table 3 Lines with most significant forecast congestion, 2033

Ref	From-to	Direction	Type
1	Woolooga – Palmwoods	SE	Hybrid inter-regional
2	Armidale – Tamworth	S	Hybrid inter-regional*
3	Bannaby – Sydney West	NE	Hybrid inter-regional
4	Tumut – Maragle	both	Hybrid inter-regional
5	Keilor – Sydenham	SE	Hybrid inter-regional

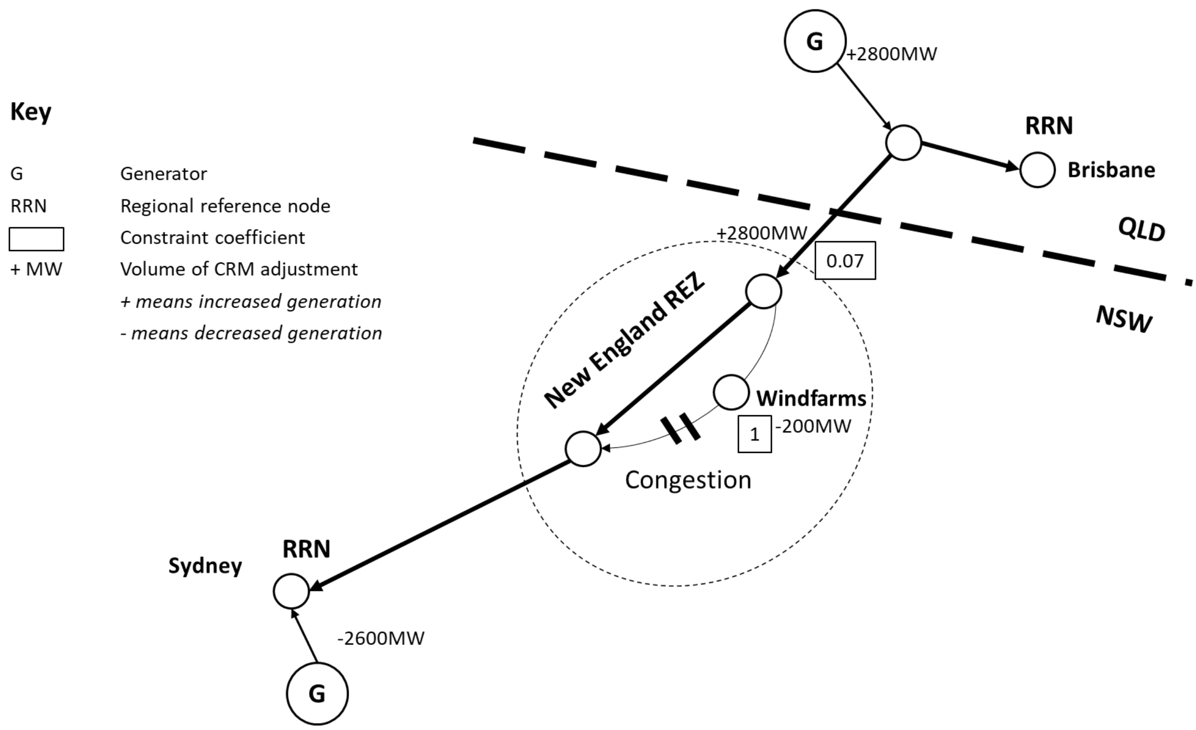
Note: (*) Also phantom congestion in this area, which appears to be hybrid inter-regional.

In 2033, there are several points of hybrid inter-regional constraint but they appear to have a disproportionate effect on the NERA results. In particular, the large counter-price flows (north) on the Qld-NSW interconnector could only be generated by a hybrid inter-regional constraint within NSW with a high level of gearing. The reported Armidale-Tamworth congestion is in the right place, but does not seem likely to have this gearing. Individual dispatch periods show that counter-price flows occur, in disorderly dispatch, even when this particular constraint is not binding.

It is inferred that the modelled outcomes are primarily driven by phantom congestion (i.e. congestion that is occurring and impacting dispatch and nodal prices but is not reported in the form of congestion prices by PLEXOS). The most likely location of this phantom congestion is in the LV (132kV) transmission network in New England which connects some of the windfarms in that REZ to the 330kV transmission back bone.

A stylised topology, and illustrative CRM trading outcomes, for this constraint is shown in Figure 15. The pattern of counter-price flows on QNI and the nodal price volatility around New England REZ is indicative of the congestion shown. But it is unclear why the materiality of these counter price flows occurs on this network topology. If this form of congestion *did* arise in 2033, it would most likely lead to the sort of impacts seen in the NERA results. Given these model limitations, our key findings for 2033 focus on qualitative, rather than quantitative, insights.

Figure 15 North NSW 2033 congestion – snapshot of a dispatch interval with congestion



Source: ESB.

The two points of congestion for 2023 and 2033 have a dominant impact on the CRM outcomes. Other points of congestion (major and minor) also have some effect and these secondary impacts can create some "noise" in the results, obscuring the dominant impacts.

3.2 Disorderly bidding can cause counter-price flows

An interconnector flow is "counter-price" when it is directed from the region with the higher RRP towards the region with the lower RRP. There is nothing intrinsically wrong with a counter-price flow:

- If bidding is cost reflective, counter-price flows would be unlikely to occur or represent efficient flows (clamping could lead to inefficiencies).
- If bidding is disorderly, counter-price flows typically represent less efficient flows depending on the underlying costs of the generators (clamping could reduce inefficiencies).

The NERA modelling shows that counter-price flows are:

- infrequent in the cost-reflective dispatch
- frequent in the disorderly dispatch, particularly on Vic-NSW in 2023 and NSW-Qld in 2033.

It is not coincidental that these are the main areas of hybrid inter-regional congestion. Where there is disorderly bidding, hybrid congestion tends to cause counter-price flows. Constrained generators bidding at the market floor price in the higher-price region will undercut unconstrained generators bidding at cost in the lower-price region. As the former displace the latter in the merit order, interconnector flows towards the higher-price region will reduce. The flows may ultimately reverse (i.e. flow counter-price) if the conditions allow and remain unclamped.

Figure 16 and **Figure 17** show these counter-price flows in the disorderly dispatch as an average daily profile over the year in 2023 (NSW-Vic) and 2033 (NSW-Qld) respectively. The horizonal axis shows the half-hour of the day (i.e. 24 refers to midday).

Figure 16 shows that, in the disorderly dispatch, the Vic RRP is generally less than the NSW RRP particularly during the daytime. The NSW-Vic interconnector flow is expected to flow into NSW (i.e. negative). But in the disorderly dispatch, it is positive during the morning on average. This is a counter-price flow. The profiles are averaged over the year, so it only indicates a counter-price flow on average and will vary day by day. In the cost-reflective dispatch, the counter-price flows are removed, with the interconnector flow towards NSW.

Figure 16 NSW-Vic interconnector flows and RRPs, 2023

Source: ESB analysis of NERA outputs.

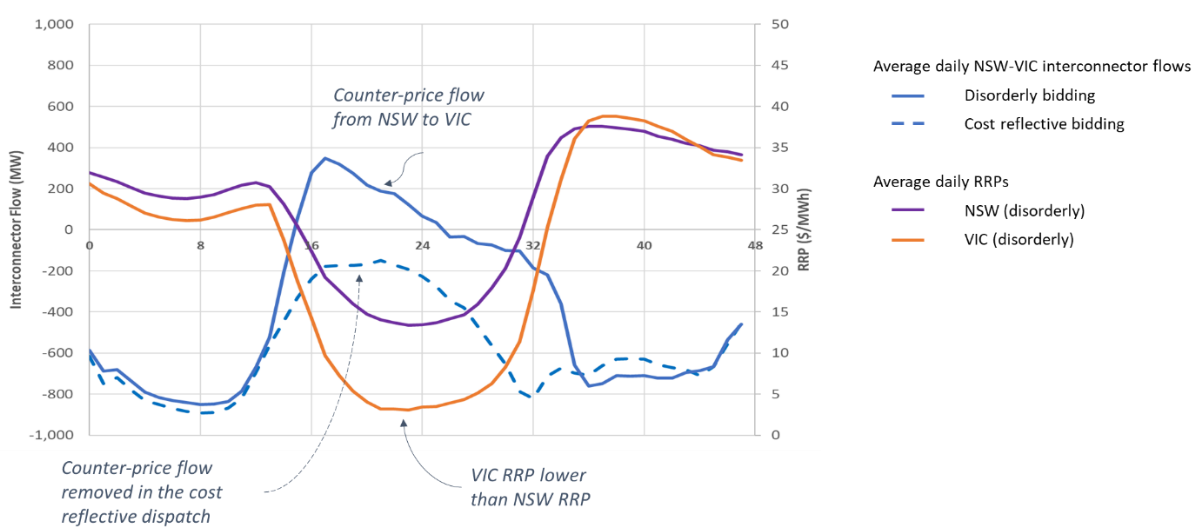
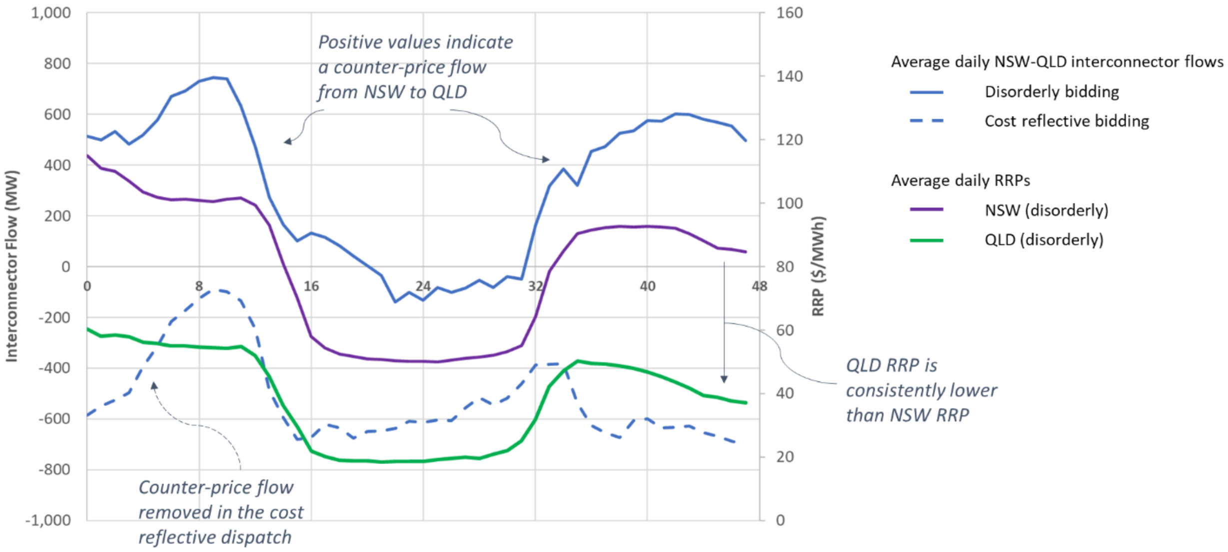


Figure 17 overleaf shows that counter-price flows are even more significant in 2033 and occur on the NSW-Qld interconnector. The NSW RRP is much higher than the Qld RRP and so interconnector flows should be towards NSW (i.e. negative on the graph).

However, in the disorderly dispatch, interconnector flows are fairly consistently positive indicating counter-price flows. In the cost-reflective dispatch, these counter-price flows are removed and interconnector flows are consistently negative.

Figure 17 NSW-Qld interconnector flows and RRPs, 2033 *Source: ESB analysis of NERA outputs.*



The counter-price flows are inefficient in the disorderly dispatch which leads to *higher* modelled efficiency gains from the CRM. These efficiency gains may be overstated if AEMO clamps the counter-price flows in practice but the size of this overstatement is unclear. Throughout the modelled period, clamping could lead to more or less efficient outcomes depending on the costs of the actual generators causing the counter-price flow.

3.3 Constrained and unconstrained generators trade in the CRM

The CRM design has evolved to cater for the complexity of the network topology and the range of constraints (refer to Appendix A). Based on historical analysis in the last four years, almost 40% of dispatch intervals affected by constraints relate to intervals where a generator is subject to two or more constraints.[22] The CRM enables efficient simultaneous trading for multiple constraints.

CRM trading will generally involve unconstrained generators (those *not* participating in a particular binding constraint) as well as constrained generators. An intra-regional loop flow constraint will cause CRM trading by unconstrained generators only in the region of the constraint. A hybrid inter-regional constraint can lead to generators in every NEM region trading. Where the form of the constraint creates a gearing effect, CRM trading quantities at the RRNs can be multiples of the quantity traded by the constrained generators. Where there are multiple binding constraints across regions in the NEM, the CRM could involve most generators that are participating in the CRM whether they are constrained by one or more binding constraints or not.

Table 4 shows the CRM sellers and buyers for the major hybrid congestion in the two modelled years.

Table 4 Regions predominantly buying or selling in the CRM

		Regions	
Year	**Affected interconnector**	**Selling into the CRM**	**Buying from the CRM**
2023	Vic-NSW North	Vic, SA, TAS	NSW, Qld
2033	Qld-NSW South	Qld	NSW, Vic, SA, TAS

Figure 18 and Figure 19 show the CRM dispatch adjustments for the period by technology by zone.

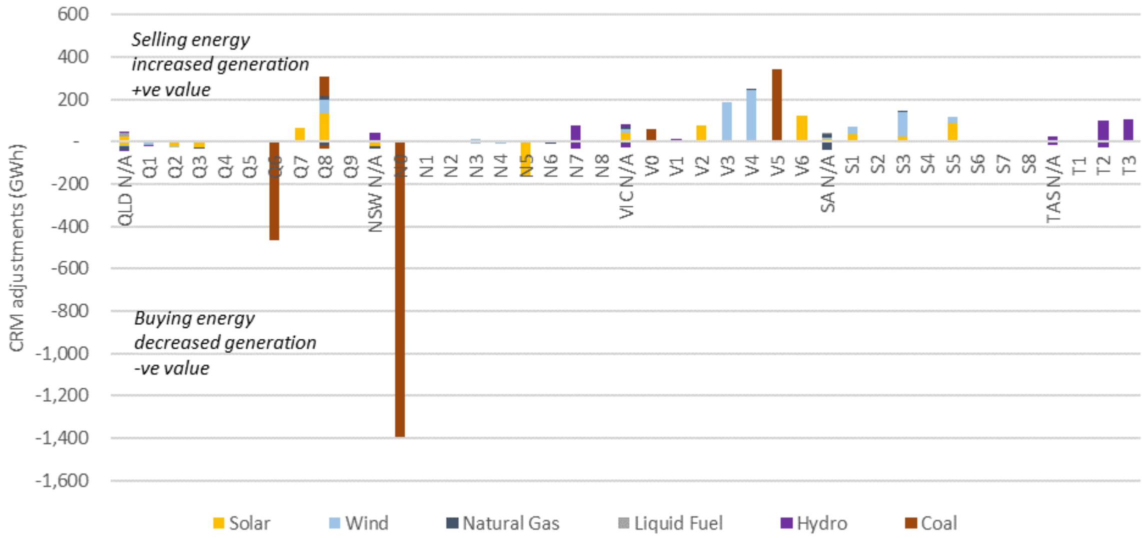
22 Constraint analysis for calendar years 2018-2022, Intelligent Energy Systems Pty Ltd, received 13-Jan-2023.

Since most CRM trading involves unconstrained generators, the region rather than the zone becomes most important. Figure 18 and Figure 19 broadly align with Table 4.

In 2023, selling is mostly from Vic, SA and Tas generators, whilst buying is mostly from Qld and NSW generators. The buying in zone Q8 goes against this trend, and appears to be due to hybrid inter-regional congestion on QNI involving generators in zones Q6 (central Qld) and Q8 (South West Qld).

The major point of congestion is Darlington Point – Wagga Wagga (N5). The NEM is almost divided in two by this point of congestion (NSW and Qld to the north and Vic, SA and TAS to the south of the constraint). N5 is a driver for the CRM trading which has a gearing effect on the interconnector.

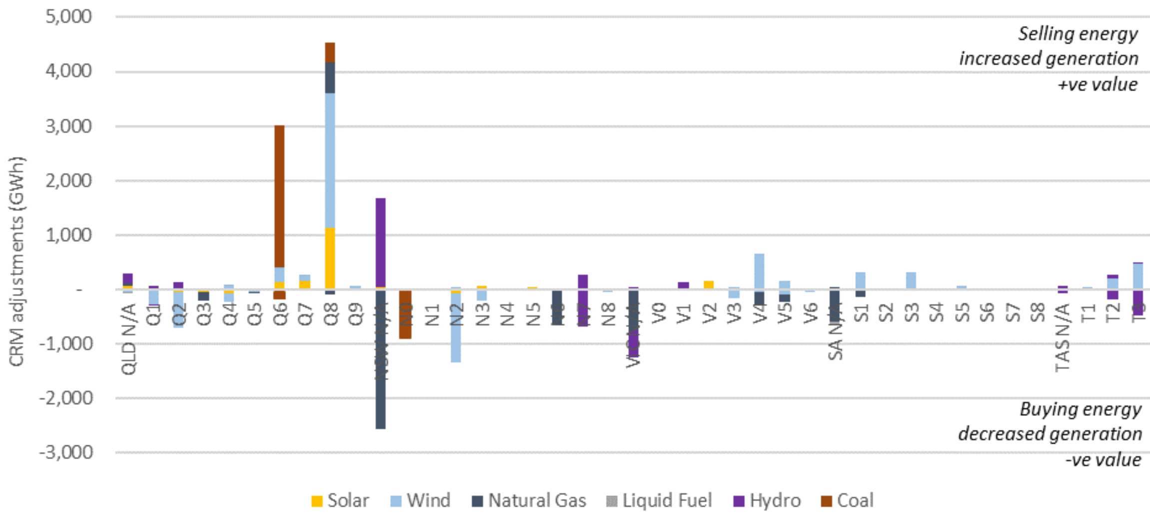
Figure 18 2023-24 CRM adjustments by technology by zone



Source: ESB analysis of NERA modelling, 221213 Data request. Note: Appendix D provides a map of the REZs for reference.

Figure 19 shows that, in 2033, selling in the CRM is primarily by Qld generators and buying is by NSW, Vic and SA generators.

Figure 19 2033-34 CRM adjustments by technology by zone



Source: ESB analysis of NERA modelling, 221213 Data request. Note: Appendix D provides a map of the REZs for reference.

3.4 CRM trading leads to a significant reduction in dispatch costs

The CRM leads to efficient flows. The dispatch of the lower-cost generators selling into the CRM replaces the higher-cost generators buying from the CRM which leads to lower dispatch costs.

Figure 20 and Figure 21 compare the costs of CRM participants by technology:

- In 2023, CRM sellers are mainly Victorian brown coal and Victorian/SA renewables, both cheaper than the CRM buyers, being NSW and Queensland black coal.
- In 2033, CRM sellers are mainly Queensland renewables and coal, both cheaper than the CRM buyers, being primarily NSW/Vic/SA gas.

Note that the scales are different between the figures.

The modelling indicates that neither the coal generators (in 2023) nor the gas generators (in 2033) are bidding disorderly because they are not constrained in the cost-reflective dispatch. Instead, it is the variable renewable generation that is bidding disorderly, causing counter-price flows and bringing more expensive fossil plant into merit in the exporting region.

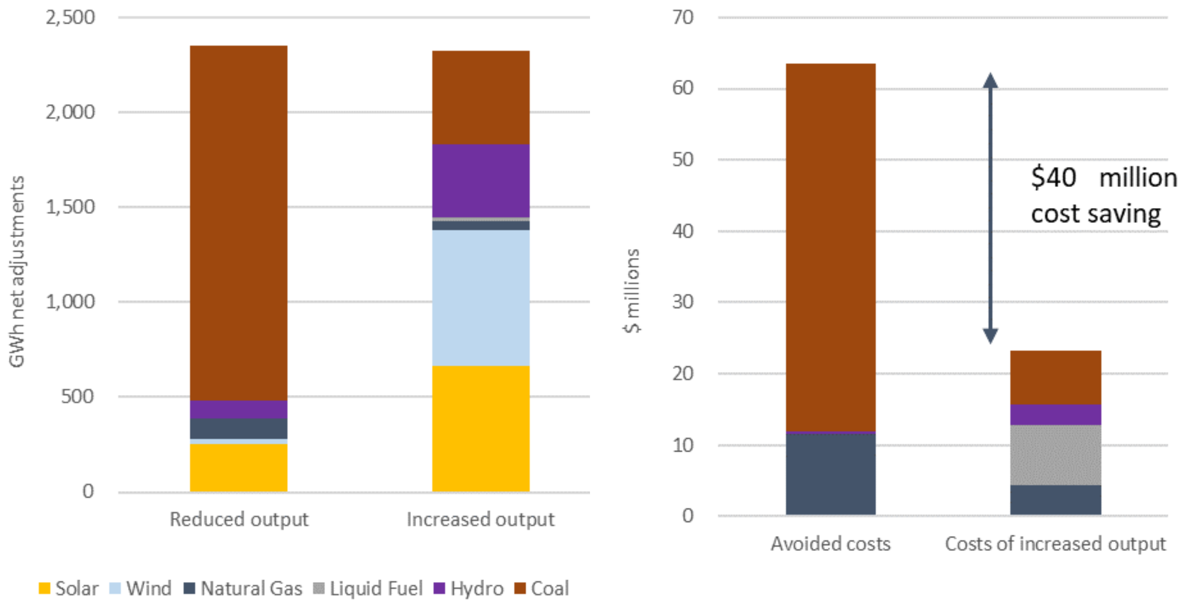
For 2023, NERA estimates a dispatch cost saving of $40m. This is relatively modest given (1) the relative difference in cost between black coal and brown coal or renewables, and (2) interconnector capacities have not yet expanded, which limits the extent to which counter-price flows can be unwound by the CRM.

For 2033, NERA estimates a dispatch cost saving of $615m. This is much higher than 2023 for two reasons. Firstly, the avoided costs in 2033 relate primarily to gas compared to coal in 2023. The efficiency increase relates to the assumed cost difference between these fuel types. Secondly, by 2033, QNI has been substantially expanded, allowing for a large quantity of CRM trading to unwind the counter-price flows seen in the disorderly dispatch.

The 2023 saving is around 1.4% of dispatch costs, whereas the 2033 saving is 28% of dispatch cost. The disproportionate change in percentage terms is due to dispatch costs falling from $2,881 million in 2023 to $2,176 million in 2033. The reduced dispatch costs reflect the progress of the energy transition, with zero-cost renewables replacing thermal coal in the generation mix. The 1.4% figure is broadly in line with overseas experience where generation mixes are dominated by fossil generation. We are not aware of any comparable studies for predominantly renewable grids.

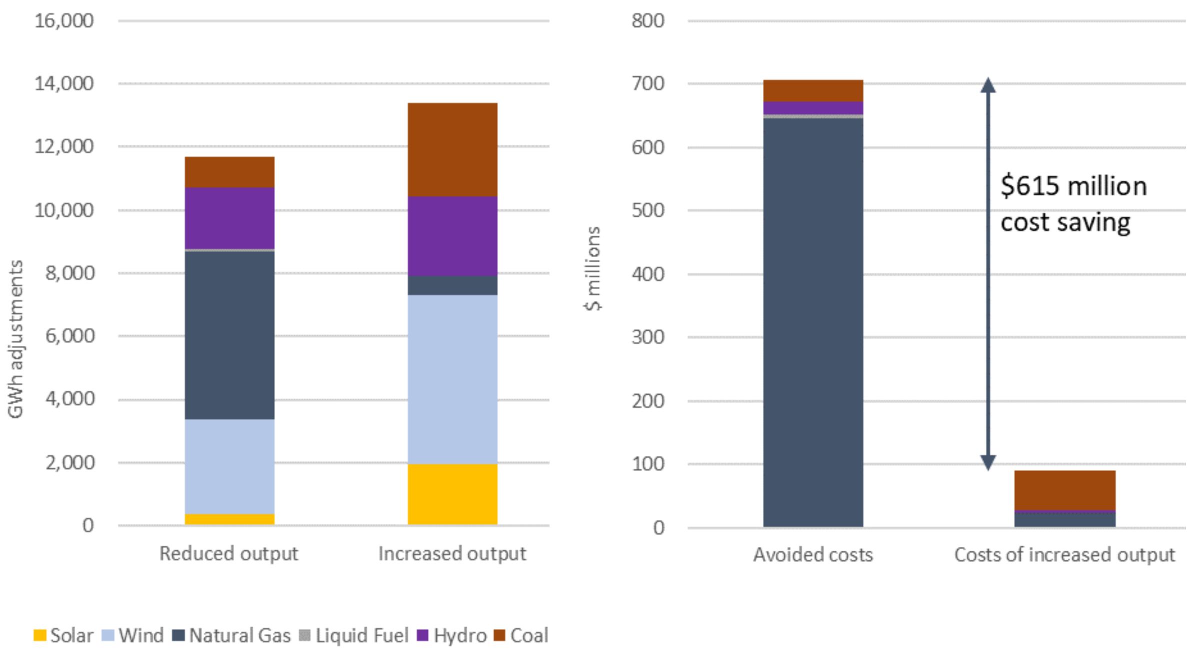
In a future energy scenario with a fully renewable grid, dispatch costs will be close to zero. Cost savings will still be possible. But the dispatch efficiencies created by the CRM will lead to a lower requirement for storage capacity, so the savings will be seen in *capital* costs rather than operating costs. NERA has not attempted to model such a scenario.

Figure 20 Dispatch adjustments and costs by technology, 2023



Source: ESB analysis of NERA modelling, 221213 Data request.

Figure 21 Dispatch adjustments and costs by technology, 2033



Source: ESB analysis of NERA modelling, 221213 Data request.

Note: In 2033, GWh adjustments of parties selling energy exceed those of buyers by 1,705 GWh. It is likely this relates to unserved energy in the energy dispatch which is fulfilled via the CRM dispatch.

3.5 Generators and customers receive an "efficiency dividend"

The short-run value-add of trading in the NEM is the difference between dispatch costs and the value to the customer of the electricity supplied. The NERA modelling assumes no change in customer demand under the CRM, so no change in customer value. Therefore, the change in value-add – the efficiency gain – is simply equal to the dispatch cost saving.

An important question is who benefits from this extra value. We use the analogy of an efficiency "dividend": just as company profits are distributed between shareholders as dividends, the efficiency gain from cheaper dispatch is distributed between generators and customers through an efficiency divided. There are three possible avenues for this dividend:

- customer savings, through lower electricity prices (i.e. RRPs)
- increased generator operating profits (NEM revenue minus generator operating costs)
- increased NEM settlement residues including inter- and intra- regional settlement residues (which are ultimately returned to customers).

The term "generators" is used as shorthand for all scheduled participants, which would include scheduled storage and scheduled load.

In the CRM scenario, RRP is unchanged so there are only two destinations for the extra value.[23] Table 5 shows the results of the NERA modelling. The "customer" component relates to a change in settlement residue which is passed through to customers.

Table 5 Breakdown of efficiency gain

	2023		2033	
Annual amount	$m	%	$m	%
Generator dividend	13	32.5%	538	87.5%
Customer dividend	27	67.5%	77	12.5%
Efficiency gain	**40**	**100%**	**615**	**100%**

Source: ESB analysis of NERA outputs, NERA detailed modelling report, 10 February 2023.

These outcomes are significant. In simple models of CRM trading with a radial constraint, all of the benefits flow to the generators trading in the CRM. But it can be shown mathematically that it is not the case in general, where there are two more points of congestion and, in particular, where the CRM trading causes new points of congestion to arise.

The NERA results suggest that customers receive a significant proportion of the efficiency dividend in 2023 but a relatively small share in 2033: albeit larger in absolute terms. The reason for this difference is unclear. It is very hard to analyse 2033 outcomes due to the problems of phantom congestion.

The customer dividend may, in part, result from the CRM unwinding inefficient counter-price flows in the energy dispatch. This dividend might reduce if these flows are clamped in the energy dispatch. That is not to say that customers are worse off with clamping, but rather that customers obtain benefits from clamping in the energy market dispatch even in the absence of the CRM. It is not possible to quantity the clamping effect given the model limitations.

23 The CRM scenario is defined as RRP based on the energy market dispatch (RRP_{NEM}). A sensitivity was performed where RRP was based on the CRM dispatch (RRP_{CRM}).

It should be emphasised that NERA's modelling only assesses short-run rather than long-run efficiency gains (i.e. changes in generator operating costs but not changes in generator investment costs).

3.6 Generators that opt in to the CRM will receive an efficiency dividend

The generators' share of the efficiency dividend is only payable to CRM participants. Generators that do not participate in the CRM will receive the same level of dispatch from the energy market and make the same operating profit as in the status quo. The efficiency dividend creates an incentive to opt in to the CRM. However, the aggregate figure does not indicate the size of the dividend received by each individual generator, or even whether it might be negative for some generators, offset by positive dividends for others. Some further conceptual and quantitative analysis is required to understand this.

The short answer is that the dividend should always be positive for an individual dispatch interval and for the full year (subject to similar trading risks of today's NEM).[24] An analogy with existing NEM trading is useful. A generator that decided to not to trade in the NEM would receive no revenue and incur no operating cost (i.e. it would receive no 'dividend' from NEM trading). All generators "opt-in" to the energy market and offer into the NEM to achieve a dispatch where the RRP is in excess of their operating costs and they will earn some operating profit (i.e. a positive "dividend"). This is a simplification given generators have start-up costs, derivative contracts etc., but does not affect the analogy.

Similarly, generators participating in the CRM will offer into the CRM such that they will only trade if the net value of the trade is positive (taking into account both CRM revenue and operating costs). The CRM is more complex than the current NEM given it is two way: a generator can sell into, or buy from, the CRM. To ensure the net value is positive, a generator must only:

- sell into the CRM if the CRM price (receivable) exceeds the increase in its operating costs
- buy from the CRM if the CRM price (payable) is less than the saving in its operating costs.

Broadly speaking, these outcomes can be assured if bidding in the CRM is cost-reflective.

Modelling issues drive counter-intuitive results.

Positive dividends should be seen in the NERA results given their cost-reflective assumptions. However, the modelled dividends are not all positive. In particular, hydro generators show a wide spread of dividends, positive and negative.

NERA's calculations do not take into account the benefit (or cost) of having higher (or lower) hydro storage at the end of the year as a result of CRM trading: in a sense they use cash accounting without any accruals. Since it is not possible, from the NERA modelling, to assess the value associated with storage, the hydro results in these figures are best ignored. Hydro generators should remain confident in the conceptual explanation of positive dividends and should understand the NERA modelling results are misleading for this technology.

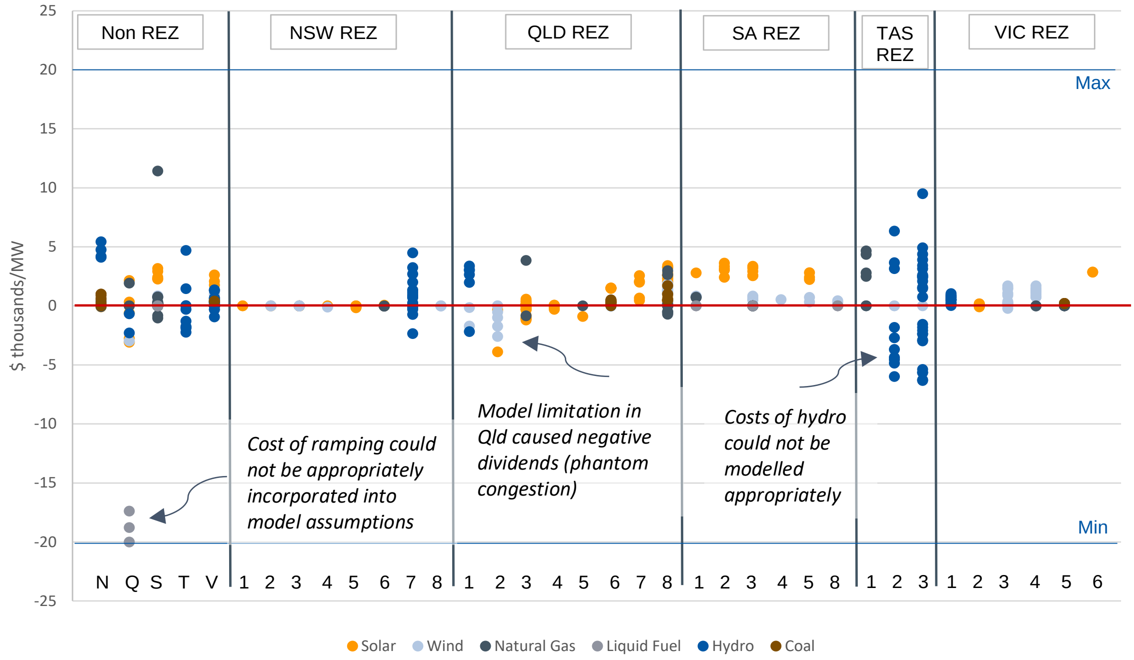
The modelling also shows some illusory negative dividends for some Qld generation in 2023. This is likely due to the phantom congestion. For 2023 (but not 2033), NERA removed the impact of this congestion on CRM clearing prices but not its impact on dispatch. The resulting anomaly between CRM traded prices and quantities means generators will sometimes show trading losses in the CRM.

For example, suppose that a wind generator in Far North Queensland (Q2) offers into the CRM at $0/MWh (i.e. its cost). PLEXOS calculates the CRM price as -$30/MWh and so dispatches the wind farm to buy from the CRM (i.e. reducing output in the CRM dispatch). The wind farm makes a

24 Generators can face losses in today's energy market e.g. depending on their bidding and risk management strategy, response to pre-dispatch information, AEMO's directions etc. Where generators have been directed and face losses, they may be eligible for compensation.

$30/MWh profit (being equal to cost minus the CRM price). But the -$30/MWh CRM price is caused by phantom congestion. After removing the effect of this, the corrected CRM price is $20/MWh. The dispatch is not changed so the windfarm is now losing $20/MWh (again, at cost minus the CRM price).

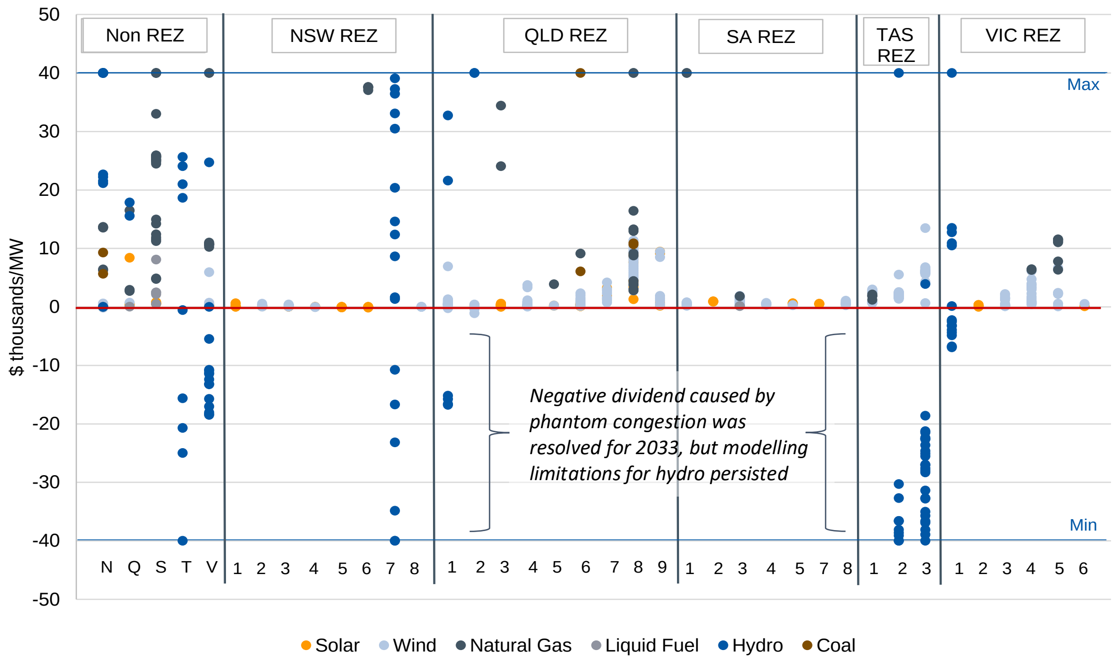
Figure 22 CRM profits due to a change in dispatch by technology and REZ, 2023-24



Source: NERA analysis of PLEXOS outputs, Figure 4.4 NERA detailed modelling report, 10 February 2023.

Note: missing REZs (e.g. S6-S7) do not have any capacity installed in the year 2023/24 under the ISP 2022 Step Change assumptions.

Figure 23 CRM profits due to a change in dispatch by technology and REZ, 2033-34



Source: NERA analysis of PLEXOS outputs, Figure 5.5 NERA detailed modelling report, 10 February 2023.

Note: missing REZs (e.g. S6) do not have any capacity installed in the year 2033/34 under the ISP 2022 Step Change assumptions.

In reality, generators might be able to increase their CRM trading profits through strategic bidding. In the first instance, this would extract some of the efficiency dividend from the settlement residue.

It might also, to some extent, lead to a less efficient dispatch, reduce the efficiency gap between the energy market and CRM and lower the efficiency dividend to customers. However, NERA has not modelled such bidding and it is impossible to gauge the likely materiality of it.

3.7 The CRM design avoids wealth transfers from changes in RRP or access

An obvious and understandable concern of stakeholders is the impact of access reform on the profitability on existing assets. In general, there are three drivers of these impacts.

- *Improvement in dispatch efficiency, leading to the efficiency dividend*
  The efficiency dividend is always positive, both in aggregate and in the amount allocated to each generator or settlement residue.

- *Impacts from changes in RRPs (as a result of changes to bidding behaviours)*
  RRP impacts aggregate to zero; it is a "zero-sum game" between generators and customers. Generator gains from higher RRPs are offset by equivalent customer losses, and vice versa for lower RRPs. Strictly speaking, it is zero sum when impacts on settlement residue are included.

- *Impacts from changes in access*
  Access is also zero sum between generators. Aggregate available access is determined by the capacity of the transmission network which is assumed for simplicity in the modelling to be unchanged by access reform. If one generator gets more access, another generator must get less. The modelling did not include a priority access scenario.

A strength of the CRM design is that the zero-sum wealth transfers are largely eliminated:

- RRP changes are avoided given the design choice to keep the RRP from the energy market (assuming no changes in bidding behaviours)
- access does not change, because it continues to be determined by the existing energy market.

The situation is much more complicated for the CMM, where all three impacts arise, together with a fourth impact (which NERA refer to as "DX") which is introduced into the modelling by phantom congestion. The CMM results are summarised in Appendix B, but there is substantial discussion in NERA's detailed modelling report.

3.8 CRM benefits remain even if there is substantial CRM opt-out

An important element of the CRM is that generators can choose whether to participate. Non-participants will forfeit the efficiency dividend. This is rational where the associated operational, commercial or managerial costs outweigh the likely efficiency dividend. In particular, renewable generators whose PPA structure relies on the receipt of NEM payments at RRP for their entire output, may find it difficult to participate in the CRM without renegotiating the contract terms.

As with any trading market, more participation means more liquidity and more opportunity for profitable trades, with associated improvements in market efficiency. Even simple congestion examples require at least two participants to complete a trade, and their bids and offers must "overlap" sufficiently for a profitable trade to occur. Any level of non-participation is liable to somewhat reduce the value of CRM trading. Ideally, there will be a virtuous circle of liquidity, whereby initial CRM activity shows the value of trading and encourages further participation. On the other hand, there is a possibility of a *vicious* circle, limited CRM activity is insufficiently valuable to encourage further participation and discourages the first movers.

To assess the relative likelihood of these alternative scenarios, NERA modelled a "partial participation" sensitivity. NERA attempted to model the rational opt-in dynamics by first calculating the efficiency dividends assuming 100% opt-in and then assuming that those generators with the lowest dividends would be the most likely to not participate. NERA selected generators with the bottom 50% dividends and extended this selection to achieve 50% non-participation by variable renewable generators (most likely parties to PPAs). Given the changing energy mix in 2023 and 2033 and the relative CRM profits for thermals and renewables; 86% of overall generation is selected to opt-in in 2023 and 56% in 2033.

For generators not participating, their dispatch level from the energy market is kept constant in the CRM dispatch. This is procedurally more complex (requiring a third dispatch to be run in PLEXOS for the full year) but is also a harder dispatch problem. The dispatch of non-participants is "frozen" and the CRM adjustments occur around these parties. PLEXOS had difficulties to solve the initial scenario (100% opt-in) and these are exacerbated with partial participation.

PLEXOS identified dispatch solutions for the partial opt-in CRM dispatch but this could be more expensive than the initial energy dispatch (i.e. delivering a negative efficiency dividend). Conceptually, this should not happen since the CRM dispatch could be identical to the energy dispatch (i.e. delivering a zero (rather than negative) dividend). To avoid periods of negative dividends which appear anomalous, NERA set the dividend to zero for these periods (i.e. the CRM partial participation dispatch was substituted for the initial energy market dispatch). NERA's results are summarised in Table 6.

Table 6 Comparison of results for CRM full and partial participation

	2023	2033
Full CRM participation		
Efficiency gain	$40m	$615m
Partial participation		
Efficiency gain	$30m	$268m
% of final dispatch from opt-in generation*	86%	56%
% of efficiency gain	75%	44%

*Source: ESB analysis of NERA outputs. *For example, in 2023, 86% refers to generation from opt-in generators and the remaining 14% refers to generation from NEM participants that retained their energy market dispatch (did not participate in the CRM).*

Substantial efficiency gains remain with reduced CRM participation. The impact of partial participation seems to be proportionately greater in 2033 than in 2023. However, the results should be treated with caution, due to the difficulties of deriving and interpreting the 2033 results.

Given the aggregation of energy market and partial participation PLEXOS results to achieve a partial participation dispatch solution, NERA was unable to reliably model revenue outcomes and the efficiency dividends are unclear. In particular, we are unable to see the extent to which incentives for further opt-in remain when there is already partial participation.

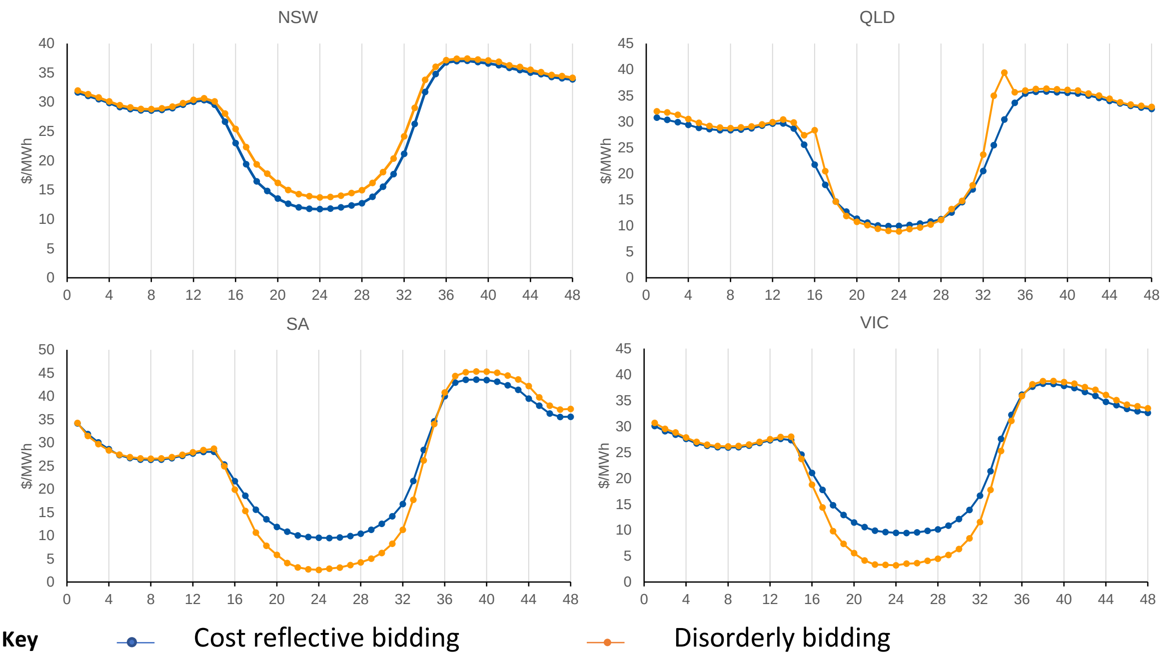
3.9 There are limited insights regarding RRP outcomes given the model caveats

NERA modelled a disorderly dispatch and cost-reflective dispatch and calculated the RRPs associated with them. The calculation of the RRP does not change, but it reflects the different input bids in response to changing incentives.

Figure 24 shows the average daily profiles of the two sets of RRP in 2023 for the two dispatches. The disorderly dispatch reflects the role of congestion in south-west NSW. The congestion and associated counter-price flows relates to output from solar farms in the nearby REZ, so it follows a daily cycle; congested during the day and uncongested at night.

A similar cycle would be expected for the cost reflective dispatch. This is true in SA, NSW and Vic. But the pattern is different in Queensland. It is caused by congestion in south-east Queensland (Woolooga-Palmwood) which tends to occur only around the morning and evening peaks. Whilst this affects Qld RRPs, it does not have a significant effect on the efficiency dividends of the CRM design.

Figure 24 Average daily RRP profile by region ($/MWh), 2023-24



Source: NERA analysis of PLEXOS outputs, Figure 4.6 NERA detailed modelling report, 10 February 2023.

The RRP is the marginal cost of an additional unit of load at the RRN. There are two dispatches run in the CRM design and hence there are two potential sets of RRPs:

- RRPs from the energy dispatch (represented by NERA in the disorderly bidding dispatch)
  RRPs from the CRM dispatch (represented by the cost-reflective dispatch).

On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to apply the RRP from the energy dispatch for settlement. The CRM scenario reflects this design choice. This means that, at least under the assumptions used by NERA, there is *no* change in RRPs compared to the status quo.

The CRM sensitivity (using cost-reflective RRPs) is financially irrelevant given this design decision. The NERA modelling report discusses the RRPs in detail since relatively small changes to RRP can swamp any efficiency dividends for generator profits.

Price impacts are front-of-mind for consumers. But there have been limited insights for the choice of RRPs given the modelling caveats (no clamping, no strategic bidding, no modelling of stability constraints etc).

The RRPs are ultimately driven by long-run entry and exit of generation and so will over the long-run reflect entry costs rather than short-term changes in dispatch. Thus the NERA results are potentially misleading in this respect. NERA did not model dynamic entry and exit and the relative magnitudes of the short-term versus long-term effects are unclear.

The NERA modelling has instead generated valuable insights in terms of the efficiency dividends returned to customers through intra- and inter-regional settlement residues.

3.10 The modelling cannot show operational and capital efficiencies of access reform for batteries when the ISP is adopted as the starting point

An important objective of access reform is to provide opportunities and incentives for storage that is located behind constraints (e.g. in REZs) to profitably trade with generators behind the same constraint. This may not be such a dominant benefit given the relative material benefits of relieving hybrid inter-regional constraints, rather than simple radial constraints. Gains from more efficient interconnector flows do not require participation of such storage. Nevertheless, it is an important aspect of the reform and formed part of the modelling objectives.

It was not possible to model disorderly bidding by storage given the complex objective function faced by storage operators, who must consider the opportunity cost of charging/discharging now versus later. Hence, the modelling understates the overall efficiency benefits of introducing the CRM design. It is also difficult to assess the efficiency dividend that storage would earn from CRM participation, and thus the additional incentive that storage has to locate behind constraints.

Alternative battery analysis simulated today's energy market (earning RRP) to the CRM design (earning nodal prices).

An alternative analysis was adopted. The analysis was designed to compare the revenue potential for storage locating at the RRN (earning RRP) compared to locating at other nodes (earning a nodal price introduced by the CRM design).

It was assumed that storage would always settle at its nodal price for its entire output. NERA developed a separate model using the nodal price results. It simulated the operational and financial outcomes for storage in such circumstances (i.e. charging when the nodal price is low and discharging when it is high). The nodal prices are taken from the cost-reflective dispatch, since these are the prices at which CRM trades settle and so the level at which storage is paid in the CRM, at least at the margin.

The nodal price at the RRN is, by definition, RRP. According to the analysis, storage located at the RRN would in effect earn a similar amount to the status quo (based on modelling assumptions and limitations for the forecast RRPs).

This simplistic analysis ignores some important factors which may drive a locational decision. Firstly, the NERA model does not incorporate transmission losses. These tend to adversely impact storage located remotely from the main RRN load, given that loss factors are lowest (i.e. worst for storage discharge) at peak times, when it is likely to wish to discharge. It also does not reflect the additional risk of not having access to the RRP at peak times; which may be necessary to back contracts referencing RRP that the storage operator has entered into. [25]

The average daily price difference is higher in 2033 compared to 2023.

Analysis of NERA's modelling identified there were greater price differentials in 2033 compared to 2023 (between the lowest and highest consecutive periods within the day). The average price differential for all nodes across the NEM is over two times greater in 2033 compared to 2023.[26]

25 In the CRM design, storage retains access to the RRP as a generator and continues to be able to back its contract arrangements. The risk relates to locating in a congested area and being constrained off in the energy market when the RRP is high. This is unlikely during expected periods of congestion (i.e. when VRE is generating at the same time) but it is possible during a major, non-credible outage of generation or transmission plant. There is a trade-off between the potential higher profits of daily price arbitrage outside the RRN and the risk of congestion during unexpected high price events.

26 Average price differential in 2023 excludes Queensland nodes most affected by phantom congestion.

The overall business case for storage improves given the enhanced price arbitrage opportunities as the generation mix transitions.

NERA's report does not show a strong incentive to locate away from the RRN, however subsequent analysis of NERA's modelling outputs identifies that the opportunities are strongly location specific.

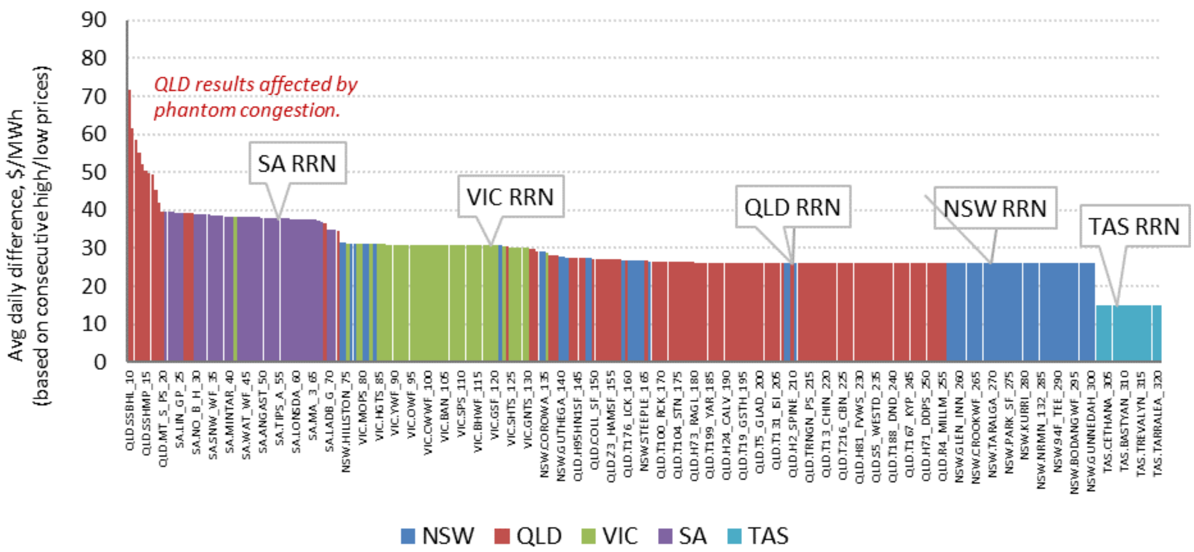
In 2023, NERA's modelling identified a shortlist of specific nodes that offered higher price spreads with local nodal prices compared to the RRN. For example, a battery located near Darlington Point had a 48% increase in profits compared to an equivalent battery located at the NSW RRN.

Subsequent analysis of NERA's outputs was performed. It was designed to identify opportunities for price arbitrage by quantifying the price difference between the highest and lowest consecutive nodal prices within each day for each node with generation. The length of consecutive dispatch intervals assumes the operation of a 2-hour battery.[27] The daily price difference was averaged across the year for each node.

Figure 25 and Figure 26 shows the ranking of average nodal price differences across all the nodes in the NEM in 2023 and 2033 respectively. The analysis is consistent with NERA's results. The materiality of the modelled price differences was not significant, particularly in 2033. Within a region, the average price differences were modelled to be up to 1-3% higher for nodes outside of the RRN. There are some more lucrative exceptions but they are location specific e.g. Northern SA and the Eastern Eyre Peninsula in 2023, and the Tumut REZ on the VIC-NSW regional boundary in 2033.

Figure 25 and Figure 26 shows the ranking of average price differences across all the nodes in the NEM in 2023 and 2033 respectively. Analysis of the locational signal provided by CRM trades is limited by the modelling complexities. This includes phantom congestion in 2023, the exclusion of dispatch intervals in 2033 and the adoption of storage planting assumptions from the ISP 2022 (discussed overleaf).

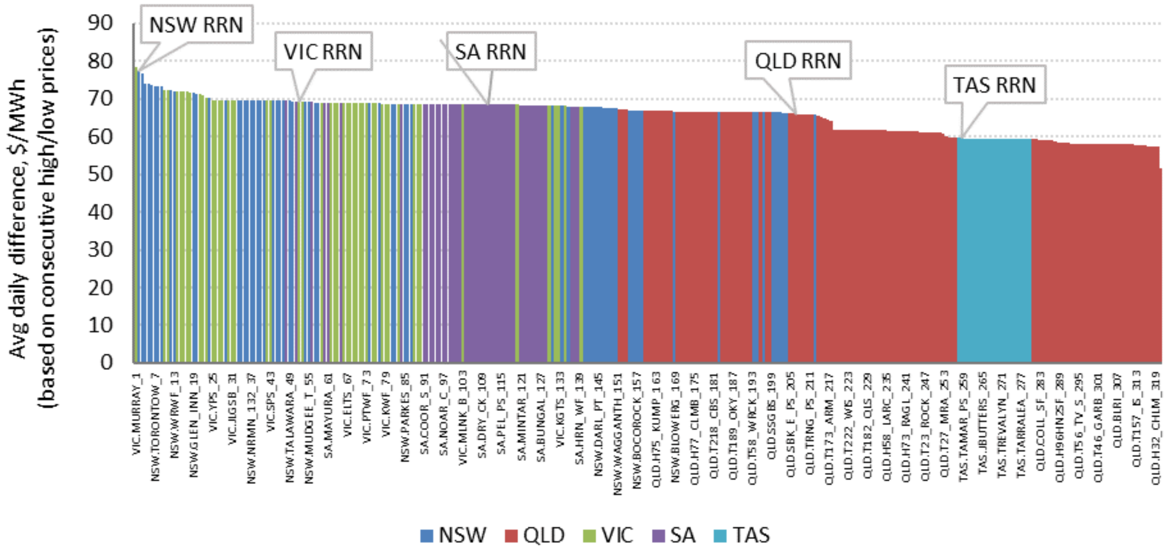
Figure 25 Highest to lowest average price differences across the day (cost reflective bidding), 2023



Note: The x-axis captures every node modelled apart from QLD nodes most significantly affected by phantom congestion in 2023. Only a subset of nodes are visible in the listing due to the font size of the x-axis.

27 There are simplifications made in this subsequent analysis. It ignores the sequence of high/low prices (i.e. low/high on day 1 and high/low on day 2 is possible even though this means you are discharging before charging in day 2).

Figure 26 Highest to lowest average price differences across the day (cost reflective bidding), 2033



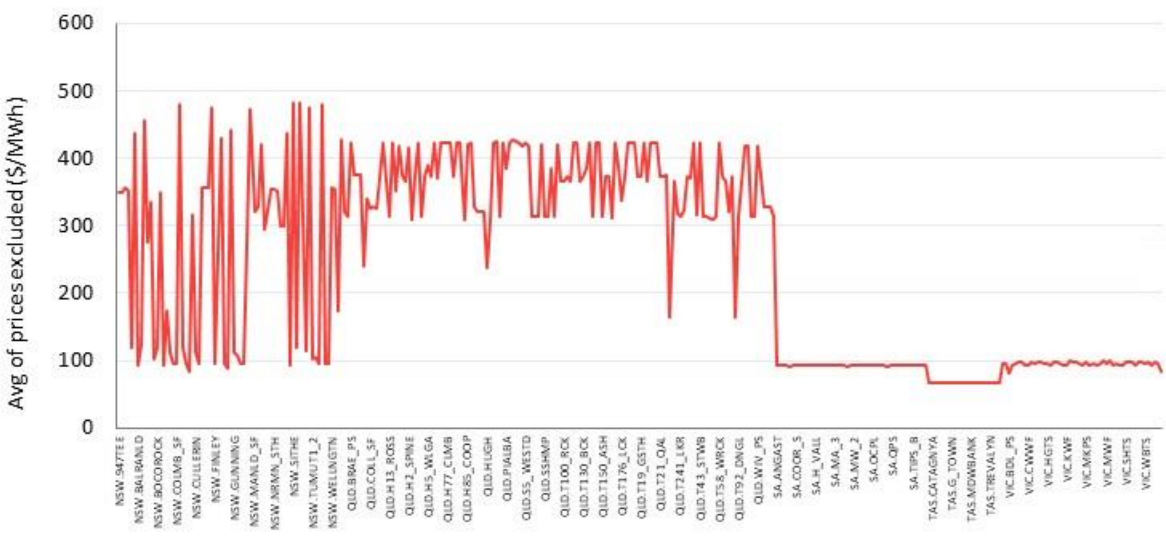
Source: IES analysis of NERA outputs, v04c received 7 February 2023.
Note: the data excludes 15% of dispatch intervals relating to infeasible dispatches (unsolved by PLEXOS). The x-axis captures every node modelled but only a subset is visible in the listing due to the font size of the x-axis.

2033 analysis excluded 15% of dispatch intervals due to PLEXOS failure to solve which would have represented some of the highest profit arbitrage opportunities.

NERA's 2033 results are particularly affected by the exclusion of more than 2600 intervals where PLEXOS was unable to solve with a feasible dispatch. 2.3% of the excluded dispatch intervals (up to 60 intervals) had prices above $14,000/MWh.

Figure 27 shows, on average, the excluded intervals had prices that were generally high, and consistently high across the NSW and Qld nodes. The battery analysis therefore excludes some of the potentially highest profit arbitrage opportunities.

Figure 27 Average prices of dispatch intervals excluded from 2033 results

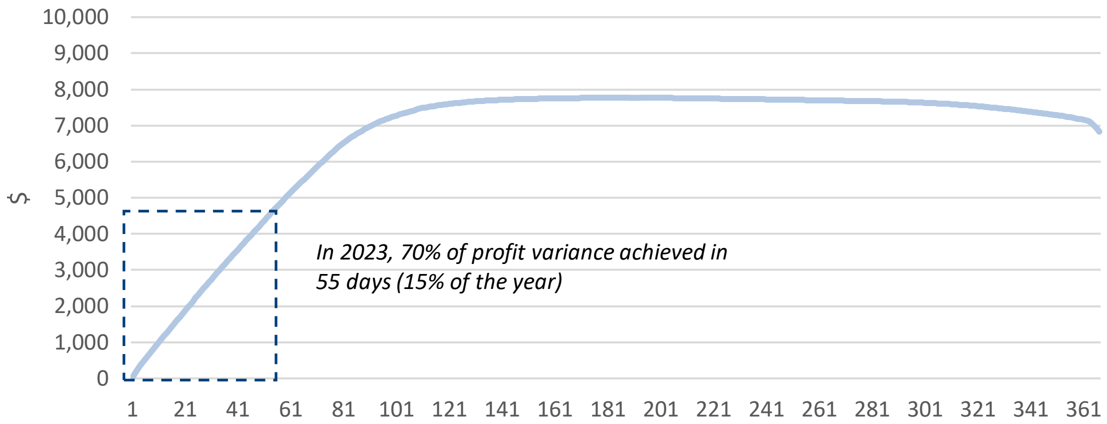


Source: IES analysis of NERA outputs, received 25 January 2023.

As a point of comparison, the impact of this exclusion can be demonstrated with reference to battery analysis in 2023. Figure 28 shows that 70% of the profit increase (from locating outside of the RRN) was achieved in 15% of the year.

2033 analysis is limited by the exclusion of a similar period. The remaining 85% of dispatch intervals were assumed to be representative of the year.

Figure 28 Cumulative profit variance for 1MW/1MWh battery located at Darlington Point (earning nodal price) compared to locating at the RRN (earning RRP), 2023



Source: ESB analysis of NERA outputs. Note: the cumulative profit variance declines at the end of the ranked days (from highest to lowest profit variance). This means that the profit arbitrage opportunities were higher at RRP than the CRM price. In practice, the battery would maximise its profit in the energy market rather than just settling at the CRM price. This strategic choice was not modelled in the analysis.

The NERA modelling cannot demonstrate the potential loss of capital and operational efficiency when it applies the ISP as its starting point.

The model applies the storage planting assumptions of the ISP 2022, which has already identified the most efficient expansion scenario and locates storage at the RRN and in REZs (equivalent to a competitive market settled at nodal prices).

The ISP has already placed storage in nodes with beneficial nodal price volatility and likely dampened price signals. In a perfectly efficient market, rents (excess of revenue over costs) are driven out by new entry. In that respect, NERA's findings that these super-profits do not seem to exist for storage might reflect the success of AEMO's modelling and planting storage entry in the ISP.

However, the ideal scenario modelled in the ISP will probably not happen without access reform.

In the current market design there is no incentive for storage to locate anywhere other than the RRN (unless there are non-market incentives such as government grants, or opportunities to sell non-energy services such as special response or system strength services). Storage gets paid the same (i.e. at RRP) wherever it locates, and if it is not close to the RRN it suffers the impact of losses and access risk discussed above. Absent of market signals, the ideal scenario of the ISP would require some form of government or regulatory intervention to encourage storage to locate where it can alleviate congestion. The potential loss of efficiency (both capital and operational) could be significant, but it cannot be demonstrated in the NERA modelling, which uses the ISP as the starting point.

4 Next steps

The ESB technical team is developing a CRM prototype and has applied historic data from NEM dispatch intervals as test cases. NERA's modelling has helped to indicate how the CRM trading will evolve as the generation and transmission mix develops, and how to future proof the CRM design. Immediate focus areas include, not exclusively, changes in dispatch outcomes for individual participants, CRM trading across regional boundaries, formulation of the inter-regional settlement residue, co-optimisation of frequency control ancillary services (FCAS) within the CRM design, level of activation of storage to relieve congestion, differing levels of CRM participation, and an assessment of edge cases.

AEMO is already considering its policy options regarding interconnector clamping as part of Project Energy Connect (PEC) and has released a consultation paper.[28] This will be an area of ongoing investigation and consultation.

28 AEMO, Project Energy Connect Implementation Paper, available at https://aemo.com.au/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper, released 15 November 2022.

Appendix A. Evolution of the CRM design[29]

There have been three key milestones in the development of the CRM design to date:

- Proposal submitted by Edify Energy.[30]
- Modified version submitted by the Clean Energy Council (CEC).[31]
- Version published by the ESB in its Directions Paper.[32]

The CRM design developed from the concept of local trades between parties affected by the same constraint equation to a broader market solving multiple constraints across the network. Different names were used by different authors for the 'congestion relief price'. The formula for the CRM price was updated from Edify Energy's model to the CEC version and then retained by the ESB.

Table 7 summarises the similarities and differences between the core concepts of the CRM design.

Table 7 Core concepts in the development of the CRM design

	Edify Energy	CEC	ESB
Participation in the CRM	Voluntary.	Same as Edify.	Same as Edify.
CRM transactions	Adjustments to the energy market.	Same as Edify.	Same as Edify.
Type of bids	Bids are received from buyers/sellers of congestion relief.	Bids would be similar in requirement and format as per the energy market bids (i.e. participants would offer full CRM supply / demand curves for their capacity).	Same as CEC.
Scope of trades	Applies to constrained parts of the network. Trades have to balance at each location (i.e. local trading occurs between parties behind a congested node).	Multiple 'constraint relief trades' can occur across the network. It does not isolate individual constraint equations and can involve constrained and unconstrained parties.	Same as CEC.
CRM price – term	Local congestion relief price (CRP).	Nodal CRM price.	Locational marginal price (LMP) (different name, same formula).
CRM settlement	CRM adjustments are settled at the difference between the RRP from the energy market and the congestion price from the CRM (applies at the constraint level).	CRM adjustments are settled at the LMP (specific to a DUID (dispatch unit identifier)).	Same as CEC.
RRP to settle energy market based on	Energy market.	Same as Edify.	Same as Edify (referred to as RRP_{NEM} in the Directions Paper although alternative RRP_{CRM} was considered as a design choice).

29 Materials in this appendix have previously been released as 'pre-reading' for the joint Senior Officials – ESB public forum held on 25 January 2023. The materials are provided here for convenience.

30 Edify Energy, Response to ESB's Project Initiation Paper, June 2021.

31 Clean Energy Council (CEC), Response to ESB's Consultation Paper, June 2022.

32 https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf November 2022

Key

	Consistency between model iterations
	Differences between model iterations

All three models are similar in concept. At its core, the CRM is an additional voluntary market whereby participants can trade dispatch adjustments and share in the efficiency gains.

The more significant step change was from the Edify Energy proposal to the CEC's. It needed to scale up the concept to work across multiple constraints, account for the complex network topology and to be able to solve in AEMO's systems. The CEC amendments were required to implement the concept in practice.

Distinct features of the Edify Energy proposal

- The CRM is only triggered after the dispatch run where there are binding constraints (i.e. LHS = RHS).
- Each binding constraint is solved to allow the relief providers and relief recipients to vary their dispatch quantity whilst still maintaining the same LHS.
- Congestion relief prices are determined by a clearing process (they are equivalent to congestion prices or the "marginal value" determined by the CRM).
- Congestion relief outcomes are settled as follows:

  Settlement \$ = G_{ADJ} *x (*RRP_{NEM} *– congestion price x constraint coefficient).*

  Terms
  G_{ADJ} CRM adjustment (MWh)
  RRP_{NEM} RRP from the energy market (\$/MWh)

Key challenges

- It assumes that only one constraint will bind at a time and each constraint can be solved one at a time and there is no FCAS co-optimisation to deal with.
- There are challenges for NEMDE to solve each binding constraint and generate a secure dispatch given a generator could be in more than one constraint and in inter and intra-constraints.
- Solving each constraint separately limits the benefits of trade
- It is not clear how participants would bid given they are exposed to an unknown RRP (*congestion relief price =* RRP_{NEM} *– congestion price x constraint efficient*, but RRP_{NEM} is unknown at the time of bidding).
- Given the uncertainty in bidding, there is a risk that participants lose money on some trades.

Resolution by the CEC

- The CEC's modified CRM adopted a holistic approach to all 'MWs term' constraints; CRM constraints are all those constraints whose costs can be relieved through the changes to the energy dispatch targets of dispatchable generation and loads.
- Participant offers represent the price and volume they would accept for increased or decreased dispatch.
- The CRM price at each location is the clearing price from the CRM.
- It maintained the distinction between:
  - energy market transactions settled at the RRP
  - congestion relief transactions settled at the CRM price.

The ESB has adopted the implementation solution proposed by CEC if certain design choices were adopted from the Directions Paper (typically referred to as 'Option 1'). The Directions Paper introduced design choices (Options 2+) as potential adaptations to this base.

Table 8 summarises the similarities and differences between the CEC and ESB versions.

Table 8 Development of design details for implementation

CRM design component	CEC	ESB	
Participation in the CRM is voluntary.	Yes	Yes	
Transactions in the CRM are adjustments to the energy market transactions.	Yes	Yes	
Actual dispatch is the combination of energy and CRM dispatch.	Yes	Yes	
The CRM adjustments to the energy market transactions are settled at the market clearing CRM prices.	Yes	Yes	
The CRM enables multiple 'constraint relief trades' to occur across the network.	Yes	Yes	
The CRM uses the same network model and security constraints as the NEM energy dispatch.	Yes	Yes	
The CRM energy prices represent the value of increasing or decreasing generation or load at each bus (node).	Yes	Yes	
Market participants can decide the extent to which they participate in the CRM by setting their offered maximum dispatch deviations allowed in the CRM.	Yes	Yes	
The NEM energy market dispatch is settled at the RRP from the energy market dispatch.	Yes	Yes, option 1 RRP_{NEM}	No, option 2 RRP_{CRM}
Differences between metered output and dispatch targets are settled at the RRP adjusted by the marginal loss factor.	Yes	Yes, option 1 at RRP	No, option 2 at LMP
NEM energy and CRM dispatch and pricing.	Co-optimised	Sequential optimisations	
The CRM FCAS dispatch and prices reflect the changes in FCAS dispatches and the marginal value of these changes in order to facilitate the optimal CRM energy trades whilst ensuring that the dispatch of energy and FCAS is secure.	Not defined	Yes	
The CRM FCAS deviations from the energy dispatch are priced at the CRM FCAS prices.	Not defined	Yes	

Key

Consistency between model iterations

Differences between model iterations

Distinct features of the CEC version

- The energy market and CRM are co-optimised as 'single pass' – energy and CRM bids/offers are concurrently considered, co-optimised, and dispatched.

Key challenges

- A co-optimised solution would involve more substantial changes to NEMDE and increase solve time.
- A co-optimised approach has the potential to result in disorderly bidding behaviour in the CRM for the units which had chosen no deviations between the energy dispatch and the CRM dispatch in order to get a better outcome in the energy dispatch. In this case, even though these units would not be practically participating in the CRM their behaviour in the CRM could distort the outcomes in the energy dispatch.

Resolution by the ESB

The ESB proposes a sequential dispatch:

- first run for the energy market dispatch
- second run for the CRM dispatch.

This allows NEMDE to solve and gives confidence that it replicates the same NEMDE structure and algorithms and minimises changes required.

It preserves the optionality of the CRM. For participants that do not participate in the CRM, it is intended that their dispatch outcomes from the energy market would be 'locked' for the purpose of the CRM dispatch immediately after. The technical implementation plan is being developed to give effect to this principle.

Appendix B. Congestion management model (CMM)

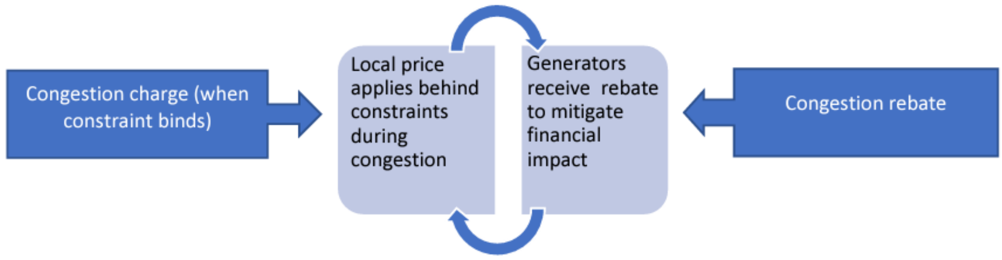
This appendix outlines the proposed CMM design, the modelling approach and outcomes.

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.

Figure 29 Concept of the CMM design



Source: ESB

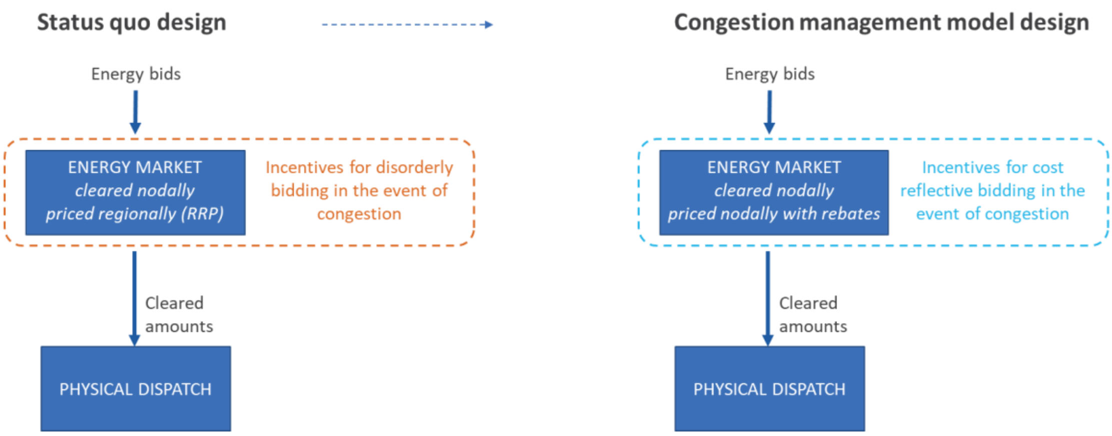
Participant bids

The CMM encourages more efficient dispatch by exposing generators to a congestion charge during operational timeframes. The congestion charge is equal to the quantity of energy dispatched (G) multiplied by the difference between RRP and its nodal price = G x (RRP – LMP). A generator is effectively settled at its nodal price (LMP) for energy dispatched.

The congestion charge in the CMM encourages a generator to bid at its 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.

Figure 30 illustrates that NEM participants face different bidding incentives in the energy market with the introduction of a mandatory LMP and a rebate mechanism.

Figure 30 Bidding incentives moving from today's energy market to the CMM



Source: ESB analysis.

Rebate allocation method

A key element of the CMM is the congestion rebate. The revenue collected from congestion charges is redistributed to market participants through congestion rebates. 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, generators are paid RRP. The generators effectively receive a congestion rebate equal to the congestion charge (which is in proportion to their generation). This leads participants to bid to maximise dispatch rather than disclose their costs. Allocating rebates on other metrics will change those incentives.

Four rebate allocation methods have been proposed.[33] In summary:

- Pro-rata access – rebates are allocated based on offered availability. The method allocates access to the RRP to each generator in proportion to their available capacity in each interval.
- Pro-rata entitlement – based on a combination of constraint coefficients and offered availability. It allocates entitlements (where entitlement = access x constraint coefficient) in proportion to availability.
- 'Winner takes all' – assigns access in ascending order of constraint coefficients. The generator with the lowest constraint coefficient in the constraint receives entitlements up to its full availability in the constraint; the generator with the next lowest factor then receives access, continuing until the constraint limit is met.
- Inferred economic dispatch – allocates access on a combination of constraint coefficients and inferred marginal costs.

Detailed modelling objectives

In addition to the objectives for the CRM design, NERA's modelling intended to calculate market outcomes for market participants according to different congestion rebate allocation methods.

Model assumptions

PLEXOS generates the dispatch, RRP and nodal price outcomes from the energy market according to the bidding assumptions in Table 9.

Table 9 Bidding assumptions as modelled for the energy market (today and with CMM)

	Bid assumptions for…	
Technology	**Energy market (today)**	**Energy market (with CMM)**
Variable renewables	Disorderly	Cost-reflective
Thermal	Disorderly	Cost-reflective
Hydro	Cost-reflective	Cost-reflective
Storage	Cost-reflective	Cost-reflective

Source: ESB.

33 Details are provided in an ESB working paper: Working paper_CMM allocation methods.

The outcomes of the energy market (with CMM) are the equivalent to the CRM. However, under the CMM, NERA developed a settlement module to process the market prices and quantities in accordance with the CMM's settlement algorithms (i.e. to calculate the congestion charges and rebates for each market participant). Generators receive different net financial outcomes compared to the CRM design.

Scenarios and sensitivities

The modelling scenarios and sensitivities discussed in this paper include:

Scenarios

- Base case (status quo)
- CMM with pro-rata access
- CMM with pro-rata entitlement
- CMM with winner takes all
- CMM with inferred economic dispatch

Sensitivities

- Exclusion of 'out-of-merit' generators

Model limitations

The CMM design has the same model limitations as the CRM but there are additional limitations for the specifics of the CMM rebate allocation methods.

Winner takes all and inferred economic dispatch

The modelling approximates the definition of the rebate allocation methods.

Winner-takes-all (WTA) assigns access to generators in ascending order of constraint coefficients. As an approximation, the modelling assumes access is allocated according to the disorderly dispatch (which, in turn, is equal to access under the CRM design).

However, the CMM-WTA variant and CRM design give different settlement outcomes, because different RRPs are used. The CRM scenario uses RRP from the disorderly dispatch (RRP_{NEM}) whereas CMM-WTA uses RRP from the cost-reflective dispatch.[34]

The NERA model will be a good approximation of CMM-WTA when there are few concurrent binding constraints, but a poorer approximation when there are many binding constraints.

Inferred economic dispatch (IED) assigns access to generators on a combination of constraint coefficients and inferred marginal cost. As an approximation, the modelling assumes access is allocated according to the cost-reflective dispatch.

In practice, this means that generators are paid RRP on their cost-reflective dispatch and their congestion rebates are set equal to their congestion charges. Similarly to the WTA variant, NERA's approach is likely to be a good approximation to the CMM IED when there are few concurrent binding constraints, but a poorer approximation when there are many.

These approximations have knock-on effects in response to phantom congestion and the treatment of interconnectors below.

34 Winner-takes-all shares the same outcomes as the CRM sensitivity where access is based on the energy market (disorderly dispatch) and RRP is based on cost-reflective assumptions (RRP_{CRM}).

Phantom congestion

Phantom congestion refers to the modelling inconsistency between congestion prices and nodal prices (i.e. LMPs). There is a strict mathematical relationship between them. NERA's settlement modules rely on this relationship holding in the prices reported by PLEXOS in its dispatch results. This relationship sometimes broke down, for reasons that remain unclear.

When this occurs, CMM settlement outcomes can be anomalous for the CMM pro rata variants (pro-rata access and pro-rata entitlements).

NERA took two approaches, in 2023 and 2033 respectively, to address these anomalies.

- In 2023, NERA ignored the LMPs reported by PLEXOS (for the purposes of CMM settlement) and instead calculated a new set of LMPs based on the reported congestion prices.[35] This meant that CMM congestion charges and rebates only arose when congestion was reported i.e. non-zero congestion prices. When PLEXOS reported a nil congestion price, the LMP was adjusted to be equivalent to RRP.[36]
- In 2033, NERA used the PLEXOS LMPs to calculate CMM settlement amounts. However, NERA explicitly calculated the anomalies that arose from this as a term 'DX'.

The modelling impact is:

- CMM pro-rata outcomes only reflect access to reported congestion. The modelling may understate the value of rebates for generators. It is not possible to quantify this level of 'missing' access.
- CMM WTA and IED variants avoid the problem of phantom congestion because they are based on unadjusted nodal prices (from the disorderly dispatch and cost reflective dispatch respectively).

Allocation of access to generators and interconnectors

In the CMM, access (i.e. congestion rebates) is allocated between generators and interconnectors. Whilst generators get a preferential allocation, access allocated to interconnectors can never be negative; at worst it is zero.[37] The CMM will rarely give rise to the situation in today's dispatch where interconnectors flow counter-price (at least until clamped) and receive negative inter-regional settlement residues (IRSR).

In the NERA model, clamping is not applied and this allows material counter-price flows to occur in today's disorderly dispatch. This effectively represents negative access for interconnectors. NERA's modelling restores negative IRSRs in the status quo to (at worst) zero in the CMM. This generates substantial wealth transfers from generators to IRSR. Whilst this is a correct model of the CMM outcomes, the size of the wealth transfers is distorted by the fact that the modelling does not clamp counter-price flows.

These wealth transfers only occur under the CMM pro rata variants.

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35 In its detailed modelling report, NERA refers to these as 'adjusted LMPs'.

36 If PLEXOS reported congestion price = 0 and LMP ≠ RRP, LMP was adjusted in post-processing; LMP = RRP.

37 Strictly speaking, there are exceptional circumstances e.g. because of FCAS constraints where interconnector access could be negative under CMM, but these are unlikely to occur in the scenarios modelled by NERA.

NERA approximates the access granted in CMM-WTA based on disorderly dispatch, which does have counter-price flows i.e. negative interconnector access. While this may be a poor approximation, it does avoid the issue of wealth transfers affecting the pro-rata variants.

NERA approximates the access granted in the CMM-IED based on the cost-reflective dispatch in which counter-price flows are rare. This means that the IED avoids negative interconnector access in both the access allocation and the physical dispatch.

The modelling limitations make it difficult to identify how alternative rebate allocation methods would operate in practice, especially since the negative residues are so material. For example, in 2033, the disorderly dispatch leads to material negative IRSRs on QNI (~$390 million over the year).

In reality, clamping would apply and the negative IRSR would not accrue to this level:

- Status quo modelling overstates the IRSR deficit.
- CRM modelling overstates the benefits to generators that keep the access.
- CMM modelling suggests adverse outcomes for generators (that would not occur in the first place).

Out of merit sensitivity

Out-of-merit (OOM) generators are those where operating costs exceed RRP. In today's energy market, generators only want access to the RRP if they are in-merit. If operating costs are less than RRP, the generator wants access (because it wants to be physically dispatched). If operating costs are more than RRP, the generator does not want access (because it'll incur the cost of physical dispatch).

The rebate methods allocate an access level to generators that bid in as available to the dispatch. Apart from the inferred economic dispatch method, this can lead to a scenario where OOM generators are included in the allocation of entitlements and access. This represents a wealth transfer compared to status quo; OOM generators would receive more revenue than today's energy market.

In the modelled sensitivity, revenue is deducted from OOM generators. OOM generators do not receive access to the RRP and earn the nodal price if called on to generate. The modelling does not subsequently allocate the surplus (RRP – LMP) to in-merit generators.

But in the actual CMM methodologies, revenue should be re-distributed from OOM generators to in-merit generators. The total generation revenues would be unchanged (except to the extent some of the reallocation is to interconnectors).

Key findings

The impacts and interactions between counter-price flows, changes to access and phantom congestion are so complex that it is not possible to distil clear explanations nor compare outcomes for the alternative CMM rebate methods.

The high-level findings are:

- The CMM achieves equivalent efficiency gains to the CRM (if there is 100% CRM participation).
- Generators are subject to wealth transfers as a result of changes to RRPs and changes to access. RRP assumptions are too limited to generate meaningful insights.
- The pro-rata methods (pro-rata access and pro-rata entitlements) appear to result in very similar access outcomes.
- Modelling for the CMM reiterates the importance of interconnectors to the efficiency gains and dividends in the access models.

- Wealth transfers to OOM generators are over four times higher in 2033 compared to 2023. They remain understated given the simplified bidding assumptions.

The CMM achieves equivalent efficiency gains if there is 100% participation in the CRM.

In PLEXOS, the energy market dispatch with cost-reflective bidding assumptions (under the CMM) is equivalent to the CRM dispatch with cost-reflective bidding assumptions.

Table 10 shows the modelled efficiency gain as a result of lower dispatch costs is equivalent for the CMM and CRM.

Table 10 System cost savings, today's energy market compared to the CRM design and CMM

	Total system costs $m	
Model run	**2023-24**	**2033-34**
Status quo (disorderly)	2,881	*2,176*
CRM design or CMM (cost-reflective)	2,841	*1,561*
Cost saving	40 *1.4%*	*615* *28.3%*

Source: NERA's modelled outputs, Table 4.2 p.32 and Table 5.3 p.62 NERA detailed modelling report, 10 February 2023.

Generators are subject to wealth transfers as a result of changes to RRPs and changes to access but RRP assumptions are too limited to generate meaningful insights.

Equivalent to the CRM, there are three key drivers of profit changes as a result of access reform:

- *Improvement in dispatch efficiency, leading to the efficiency dividend;* the efficiency dividend for the CMM is always positive and is equivalent to the CRM.
- *Impacts from changes in RRPs (as a result of changes to bidding behaviours);* bidding incentives change under the CMM and hence RRPs will reflect the change in bids and offers (compared to the status quo and the CRM scenario).
- *Impacts from changes in access;* the rebate allocation method determines the level of access granted to each generator (compared to the status quo and the CRM scenario where it is determined by the energy market dispatch).

The analysis below excludes the impact of RRP changes. Small changes in RPPs can trigger material changes in profit outcomes that swamp the other profit drivers. There are limited insights from the modelled RRPs given the caveats (no clamping, no strategic bidding, no modelling of stability constraints etc).

Table 11 and Table 12 summarise the aggregate profit changes for generation as a result of the efficiency dividend and change in access for 2023 and 2033 respectively.

The generators' efficiency dividend is the same across all CMM scenarios because of identical bidding and dispatch. They are equivalent to the CRM design. The generators' efficiency dividend is less than the total efficiency gain from lower dispatch costs ($40m in 2023 and $615m in 2033). Customers receive the remainder as their efficiency dividend. The change in access indicates the wealth transfers between customers and generators.

In 2023, Table 11 shows that generators receive additional dividends from access for the pro-rata methods. In 2033, Table 12 shows the reverse is true and *customers* receive additional dividends from access for these same methods.

However, the outcomes are misleading given the treatment of negative IRSRs that are not clamped in the energy market and which can generate adverse outcomes for generators in the CMM design (that would not occur in the first place).

Outcomes for the winner-takes-all and inferred economic dispatch should be disregarded for this reason. The main insight gained is that pro-rata methods (pro-rata access and pro-rata entitlements) appear to result in very similar access outcomes.

Table 11 Aggregate profit changes for generation, 2023

Scenario	Efficiency dividend $m	Change in access $m	Profit change $m
Pro-rata access	13.4	18.8	32.2
Pro-rata entitlement	13.4	18.5	31.9
Winner-takes-all	13.4	-	13.4
Inferred economic dispatch	13.4	-3.2	10.2

Source: NERA detailed modelling report, Table 3, page v.

Table 12 Aggregate profit changes for generation, 2033

Scenario	Efficiency dividend $m	Change in access $m	Profit change $m
Pro-rata access	538.5	-26.6	511.9
Pro-rata entitlement	538.5	-24.2	514.3
Winner-takes-all	538.5	-	538.5
Inferred economic dispatch	538.5	-173.8	364.7

Source: NERA detailed modelling report, Table 4, page v.

Wealth transfers to out of merit generators are over four times higher in 2033 compared to 2023. They remain understated given the simplified bidding assumptions.

The Directions Paper included a series of design choices regarding the treatment of OOM generators in the CRM design.[38]

The out-of-merit issue arises for the CMM and the CRM in different circumstances:

- In the CMM, if the rebate allocation method does not consider costs, it will grant access to both in-merit and OOM generators.
- In the CRM design, access is decided by bids into the energy market. Arbitrage opportunities between the energy market and the CRM exist for generators including OOM that would not be available in today's market design.

The CMM sensitivities for pro-rata access and pro-rata entitlement give an indication of the out-of-merit issue.[39] Table 13 quantifies the value of the wealth transfers by technology.

38 Refer to section 4.2.3 of the Directions Paper.

39 The treatment of out-of-merit generators was considered in the ESB working paper for the CMM rebate allocation methods: Working paper_CMM allocation methods.

Natural gas generators are the highest beneficiaries of OOM wealth transfers, unless the market is designed to avoid them.

In the context of the CRM design, the quantum of the wealth transfers is indicative and understated given:

- There is no strategic bidding by any technology which could otherwise maximise the OOM opportunities available in the CRM design.
- Storage (hydro and batteries) are always assumed to bid cost reflective. There are also limits on this estimation of costs in PLEXOS which could affect their costs in reality.

Table 13 Profit transfers as a result of excluding OOM generators from receiving access payments

	2023 profit transfers $m		2033 profit transfers $m	
	Pro-rata access	Pro-rata entitlement	Pro-rata access	Pro-rata entitlement
Natural gas	-6.7	-6.9	-21.1	-25.6
Battery	-	-	-8.7	-8.6
Liquid fuel	-	-	-2.3	-2.2
Hydro	-1.2	-1.3	-1.3	-1.3
Total	**-8.0**	**-8.3**	**-33.5**	**-37.8**

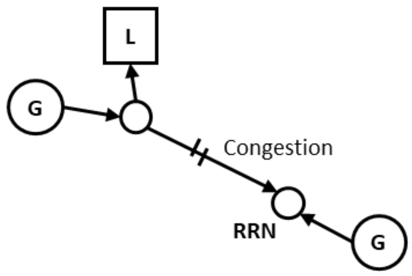
Source: ESB analysis of NERA modelling dashboards for 2023 and 2033.

Appendix C. Network topology types

The figure below summarises the network topology types discussed in 2.1. It provides an easy reference sheet for readers to understand the types and identify points of difference.

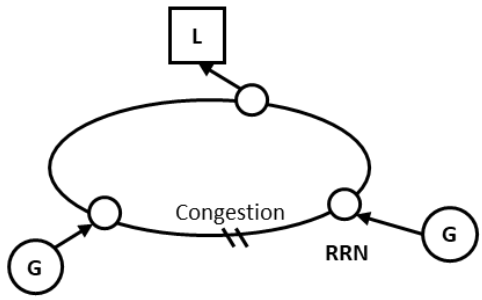
Figure 31 Network topology types

"Simple radial"



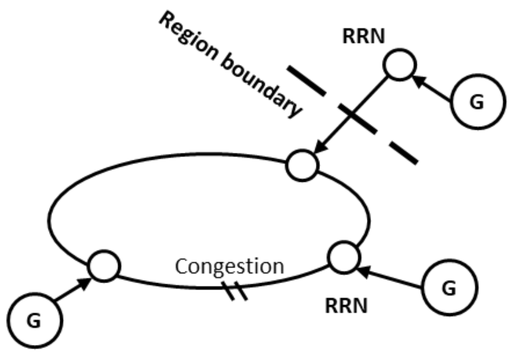
Simplest example of a radial constraint. Congestion relief can be traded between two parties without affecting dispatch beyond the constrained zone.

"Intra-regional loop"



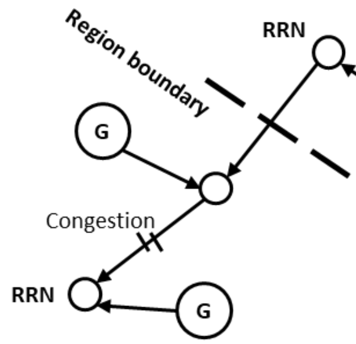
More complex and more common topology with load and generators in a loop. No interconnectors participate. Congestion relief trades need to be balanced by parties outside the constrained zone.

"Inter-regional loop"



Inter-regional constraints can be caused by an interconnector (pure) and/or generator participation (hybrid). There can be a multiplier effect when congestion relief trades balance across the regions.

"Inter-regional radial"



An example of a radial constraint that crosses a regional boundary and involves an interconnector. There can be CRM trading but there will no multiplier effect..

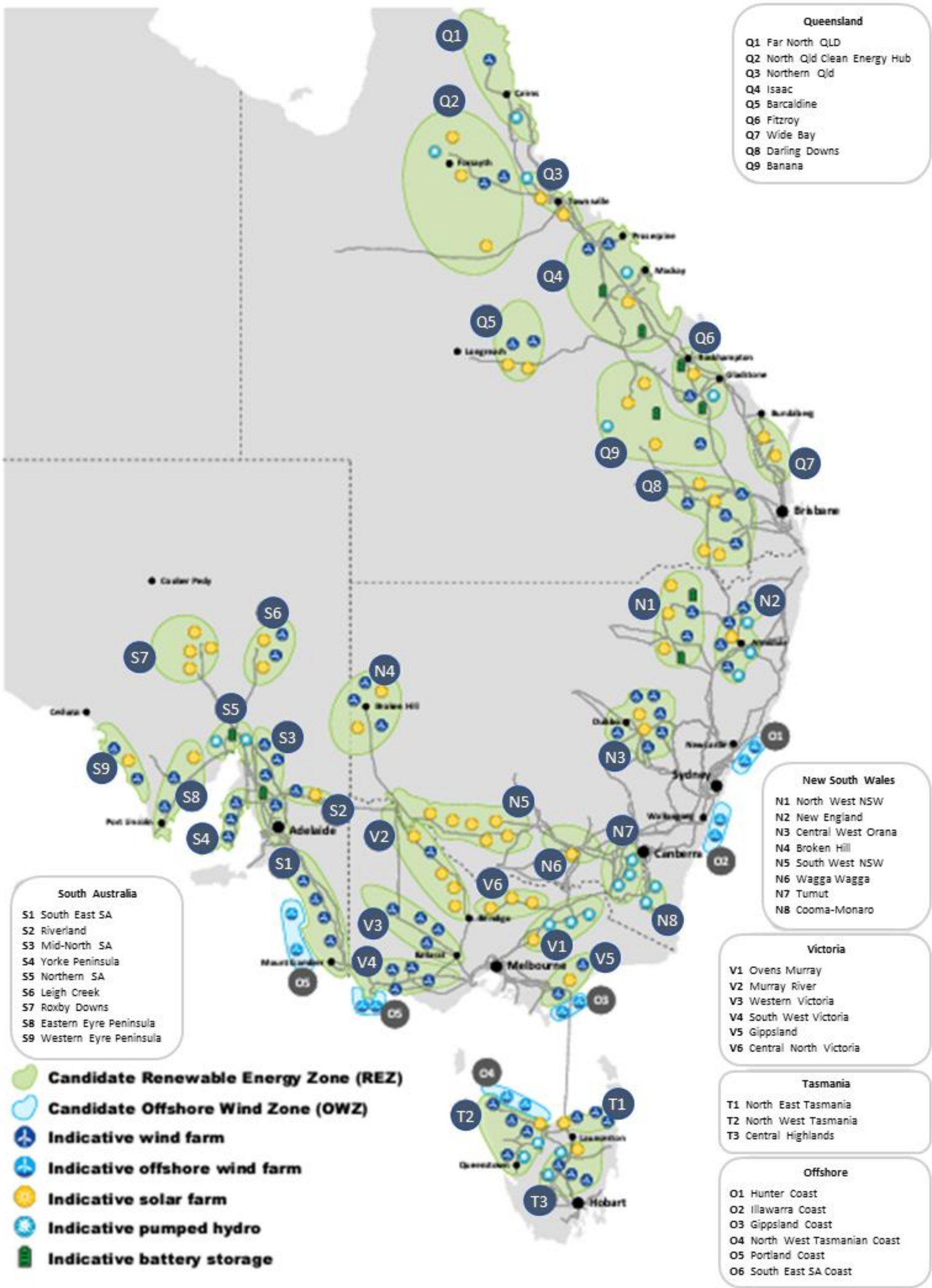
Key	
G	Generator
L	Scheduled load
RRN	Regional reference node
RRP	Regional reference price

Source: ESB.

Appendix D. Map of renewable energy zones

Figure 32 shows a map of the 41 short-listed renewable energy zones (REZs) including six offshore wind zones (OWZs) across eastern Australia according to the 2022 final ISP. NERA adopts the number references of these REZs in its modelling.

Figure 32 2022 REZ including offshore wind zone candidates



Source: AEMO, 2022 ISP, Appendix 3 Renewable Energy Zones, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a3-renewable-energy-zones.pdf?la=en

Note: NERA introduces two additional zones; 'N0' and 'V0'. 'N0' refers to Mount Piper, Eraring, Liddell, Bayswater and Vales Point which have coal plants in 2023-24 and are forecast to have new wind and/or battery plants in 2033-34. The sites are located closer to the NSW regional reference node of Sydney West than the REZ geographical boundaries. 'V0' includes Yallourn power station which has coal in 2023-24 and forecast to have new wind in 2033-34. It is located closest to 'V5' Gippsland REZ.

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