ENERGY SECURITY BOARD

Transmission access reform

Cost benefit analysis

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Executive Summary

The Energy Security Board (ESB) has worked with stakeholders to develop four options to improve the way congestion is managed in the National Electricity Market (NEM). There are two dimensions to the congestion challenge. The first aspect is to attract the right combination of generation and storage investments, in the right places, to ensure that the level of congestion in the system is consistent with the efficient level. Second, when congestion occurs, the market should dispatch the least cost combination of resources that securely meets demand. Two of the four options address the operational timeframes objectives, and two address the investment timeframes objective.

Operational timeframes	Investment timeframes
Congestion relief market (CRM)	Congestion fees
Congestion management model (CMM)	Priority access

The report brings together our analysis of the costs and benefits of these options, including new and previous market modelling of the NEM, application of international studies of access reform to the NEM, qualitative analytical assessments, AEMO estimates of AEMO system costs and estimates of industry implementation costs.

Our analysis demonstrates that all of the hybrid model combinations (i.e. options that involve both an operational timeframe solution and an investment timeframe solution) result in substantial net benefits to consumers. These are primarily made up of operational benefits from dispatch efficiency gains under the CRM and CMM, and investment efficiency gains under the congestion fees or priority access models. The model with the highest quantified net benefits is a combination of the CRM and priority access model. In addition, we have identified a range of qualitative factors that supports this preference.

Preferred model – Hybrid model comprising CRM and priority access

The ESB's preferred model results in:

1. Quantified net benefits estimated at $2.1-5.9 billion,[1] plus
2. A possible reduction in the cost of capital for storage and generation investors. We have not quantified this benefit, and instead only estimate it in directional terms (a decrease). To the extent the reduction does arise, this reduction in costs would increase the net customer benefits of the reform, plus
3. A reduction in emissions by 23 million tonnes.

This option also has the advantage that it avoids the need to redistribute value between existing market participants, as would occur under the CMM.

What is the problem?

Congestion in electricity systems occurs when generation is constrained down or off due to the operational limits of a particular part of the transmission network. Congestion is a feature of all well-designed electricity systems internationally and is common in Australia's National Electricity Market (NEM).

1 Figures are given in net present value (NPV) terms over the period 2023-2050.

It would be wasteful to build a transmission system that can transport all generation on the windiest or sunniest of days, since at these times, energy supply exceeds demand. Eliminating all congestion would involve building a huge transmission system. Instead, it is more efficient to have a smaller system and manage congestion by efficiently rationing which generators get to use it.

Congestion needs to be carefully managed, since it prevents the least cost combination of generation resources from being dispatched. Congestion arises when a higher cost generator in one location must be used instead of a lower cost one at another location – using the lower cost generator would exceed the physical limits of a particular part of the transmission network, while using the higher cost generation would not exceed the limits, given the generators' relative locations.

In the NEM, generators do not face the costs they impose on third parties when, as a result of their use of the transmission network, another generator is curtailed. This type of regulatory failure is categorised as an **externality**, where one party's actions have an unpriced impact on third parties. The inefficient costs are borne not by the party undertaking actions but by others, limiting the incentives on the party taking the action to ensure costs are minimised. Similarly, storage and flexible demand side resources are affected by a positive externality. Because storage is not paid for the benefits they provide when charging and helping to alleviate congestion, their incentive to do is diminished.

The poor management of congestion in the NEM design will be increasingly tested as the power system transforms to one with low emissions from a large fleet of renewable generation. The poor management of congestion is not consistent with the National Electricity Objective:

- **Poor congestion management is not in the long-term interests of customers.** Because investors do not pay for the shared network, they do not properly integrate network costs into their decision making. In the longer term, this leads to inefficiencies in the location and nature of generation and storage investments. In real time, the costs of using the transmission network include the costs of losses and congestion. While they are exposed to the volume of output lost to congestion, they are not exposed to the cost of congestion if they are dispatched, leading to operational inefficiencies. The structure of the NEM combined with the way congestion is managed in the NEM's regional market gives rise to inefficiencies in the operation of interconnectors and interstate trading.

- **Poor congestion management is also not in the long-term interests of investors**. While investors do not have to pay to use the network, they also obtain no right to use the network. A connecting party not only avoids paying the full cost of its own impact on the network, it can impose costs on other parties already connected. This externality introduces significant and unmanageable risks for participants who may invest wisely but then face having their opportunities to be dispatched eroded by decisions taken by others. This is exacerbated by the 'winner takes all' nature of constraints. This risk can be expected to be priced into investors' decision making over time and increase prices faced by consumers. It will also hinder the ability of jurisdictions to implement REZs while maintaining competition.

Inefficient operation of plant and utilisation of the network has been shown to not only increase costs but also to increase emissions. This implies that the cost of meeting emissions targets will be higher than they should have been with appropriate market design changes. The current arrangements can even support investment in generation in areas which are already facing high levels of congestion, because new entrants are able to be dispatched at the expense of existing generators. While this investment may be privately profitable, it is not necessarily socially efficient if it displaces existing low-cost generators. As little *additional* cheap and low emission energy is generated as a result of these investments during periods of congestion, we will need to make more investments than are necessary – in storage, generation and transmission – to replace retiring generators in order to reliably meet demand while reducing emissions.

Costs and benefits of the proposed solutions

Each of the models considered in this document seeks to align privately profitable outcomes with the efficient outcome from a whole of system perspective. The CRM and CMM address operational inefficiencies, resulting in a lower cost and emission combination of generators to meet demand for any given mix of generation assets. The other two options (congestion fee and priority access model) address investment inefficiencies, resulting in fewer, better located generators and storage to meet demand and emissions reductions objectives – achieving the same results using fewer resources. A hybrid model is needed to collectively address the operational and investment issues.

Table 1 (page 9) provides a summary of the mid-point estimated benefits and costs of the reforms for each combination of options. Figure 1 (page 11) shows the low and high range estimates for each.

The estimates presented in this report in large part are derived from market modelling. Such modelling is inherently difficult, particularly in determining the costs of the current arrangements given the existing complex and perverse incentives. As a result, this report is conservative in estimating both the low and high estimates of the net benefits of the options. International studies of similar reforms elsewhere indicate similar – if not considerably higher – potential benefits. The discussion below provides an overview of the modelling approach and results.

Operational benefits

Both the CRM and CMM are estimated to give rise to similar efficiency savings in dispatch. These benefits are driven by the more efficient use of existing generation and transmission assets, such as a substitution from high-cost generation to low-cost generation during periods of congestion.

The benefits in operational timeframes have been quantified using two main sources of information. First, the ESB commissioned NERA Economic Consultants (NERA) to undertake a NEM-specific study to analyse the operational benefits arising from introducing the CRM or the CMM.[2] This approach models the total cost of generation in two years (2023-24 and 2033-34) in a scenario where generators face the status quo incentives as well as a scenario where the CRM or CMM is introduced. The difference in total generation cost in these two scenarios provides a measure of the operational benefits of the CRM or CMM. Second, the ESB applied the benefits found in a range of studies of the operational benefits of introducing reforms that have the effect of pricing congestion in other jurisdictions. These previous studies outline the cost savings in terms of a percentage of fuel costs, and these percentages are then applied to the NEM.

These figures provide a range for the what the total benefits of the reform in operational timeframes may be. Because the CRM is voluntary and, so less disruptive to the contract market, it can be implemented sooner with higher operational benefits: $330m - $640m compared to $290m - $550m for the CMM.

Emissions

Emissions reductions are quantified based on the fuel substitutions due to the various models. This results in an estimated 21m - 23m tonnes of emissions savings by 2050. This is equivalent to shutting a large coal-fired power station like Liddell entirely four years early, avoiding fuel costs and emissions but with no impact on reliability.

2 NERA (2023), Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM – prepared for the Energy Security Board. See also the ESB companion document, Transmission access reform Modelling the congestion relief market, February 2023.

Table 1 Summary of total impacts, mid-point NPV 2023 – 2050 ($billions 2022)

	CRM alone	CMM alone	Congestion fee alone	CRM + congestion fee	CMM + congestion fee	CRM + priority access*	CMM + priority access*
Operational benefits	$0.49	$0.42	$0.00	$0.49	$0.42	$0.49	$0.42
Capital and fuel cost savings from more efficient locational decisions	$0.00	$0.00	$3.80	$3.80	$3.80	$3.80	$3.80
AEMO costs	$0.06	$0.01	$0.01	$0.07	$0.02	$0.08	$0.02
Participant costs	$0.18	$0.19	$0.00	$0.18	$0.19	$0.18	$0.19
Net benefits	**$0.24**	**$0.22**	**$3.79**	**$4.03**	**$4.01**	**$4.03**	**$4.00**
Net benefits exclude the following changes in market disruption and emissions							
Market disruption; redistribution of wealth between existing generators	-	↑	-	-	↑	-	↑
Change in CO_2 emissions (tonnes)	-23m	-21m	-	-23m	-21m	-23m	-21m

** On a stand-alone basis the priority access model is unlikely to have the highest net benefit (and may have net costs) because it may not improve operational efficiency (and may decrease operational efficiency) for reasons outlined in section 3.4.2. For these reasons the costs and benefits of implementing it on a standalone basis have not been determined.*

Note: Rounding difference in table for CRM, CRM + congestion fee and CMM + priority access.

Investment timeframe benefits

Given the enormous scale of the investment task arising as a result of the energy transition, any reforms that have the effect of improving investment efficiency have a large impact. Modelling suggests that by 2040, under the congestion fee or priority access model, we can have a system with 20 per cent less capacity but still delivering the same level of reliability and emission reductions because the average utilisation of generators improves, saving $2.1 to $5.9 billion in NPV terms.

The ESB used two main techniques to quantify the investment savings from more efficient locational decisions. First, we reviewed international studies measuring the cost savings associated with market models that expose generators to congestion pricing. These studies provide an indication of the possible benefits of addressing the externality (namely that generators do not face costs of congestion) in the NEM. Second, we applied previous modelling work completed by NERA specific to the NEM to quantify the benefits of improving locational signals for new connecting generators in the NEM.

These two approaches provide a range for what the total benefits of the reform in investment timeframes may be.

Risk

The CRM and priority access model has potential to reduce the cost of capital for generators. We have not sought to quantify the magnitude of these changes, however, we note that even small reductions in the cost of capital are likely to represent significant cost savings given the size of the investments required over the period. The CMM and congestion fee models have more ambiguous impacts on risk.

The ESB commissioned a report by Cambridge Economic Policy Associates (CEPA) on the cost of capital impacts of the reform options. The analysis considered the cost of debt, mainly considering default risk, and the cost of equity, considering systematic risk in the framework of the capital asset pricing model. CEPA's analysis indicates that:

- The CRM alone may reduce downside risk and increase expected cash flows, which lowers the risk of default assuming gearing is unchanged.
- The CRM and priority access model provides additional protection against later cannibalisation against new entrants, which may further reduce downside risk and increase expected cash flows.
- Assuming that gearing is unchanged, the risk of default may be lower under the CRM and the priority access model, pointing to a lower cost of debt.
- The reforms are less likely to have a material impact on systematic risk, and therefore may not affect the cost of equity in either direction.
- In combination, these conclusions indicate an overall downwards impact on the risk factors that determine the cost of capital resulting from the implementation of the CRM and priority access reforms.
- In practice, the impact on the cost of capital depends not only on the direction of these effects but also their magnitude.

CEPA's report is published in conjunction with this cost benefit analysis.

Costs

The costs of the reforms are estimated to be an order of magnitude less than the benefits when the investment and operational options are combined. AEMO costs associated with the CRM are slightly higher than the cost of the CMM when implemented alone or in combination with the investment timescale options. Market participant IT costs are estimated to be similar, however the costs associated with contractual disruption are lower under the CRM than the CMM.

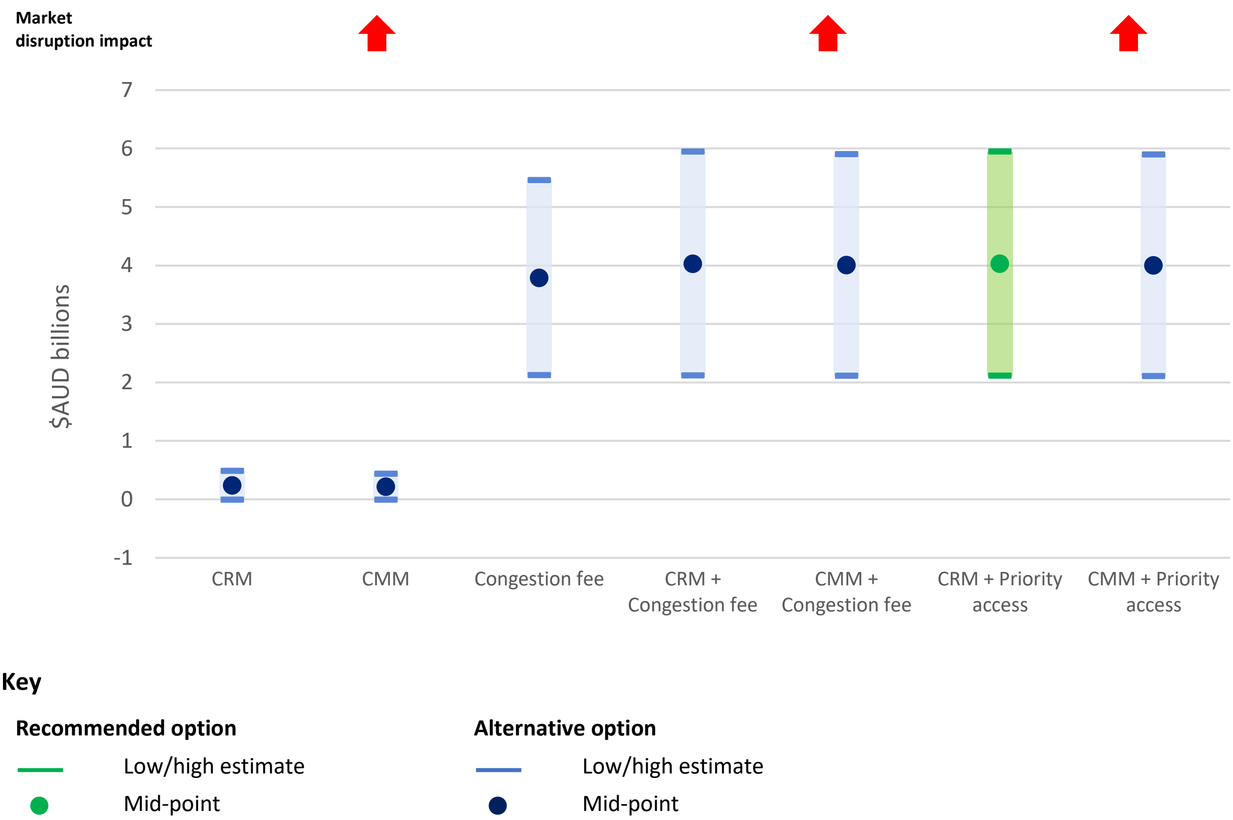
To develop the cost estimates, the ESB has worked with AEMO and EY to prepare new estimates of AEMO's implementation and ongoing costs for the CRM, congestion fee and priority access model. This involved creating a system impact heatmap which determines which systems are likely to be impacted by each option. Given that further work is required to settle the detailed design of these options, these estimates are necessarily high level, with range of uncertainty of ± 50%.

To assess the likely IT and legal costs of market participants, we have relied on previous work by the AEMC as part of the Coordination of Generation and Transmission Investment Review. As with our estimate of benefits, these historic estimates provide a reasonable starting point but have been adjusted to reflect the specifics of the policy options now being considered.

Preferred option – congestion relief market and priority access

The case for reform is clear, with estimated benefits for the hybrid options outweighing costs by an order of magnitude. The choice of hybrid is less clear cut, with the low estimated net benefits of each being $2.1 billion, and the high estimates of $5.9 billion.

Figure 1 Range of net financial benefits of model options ($ billions 2022)



The ESB's preferred option is the CRM in combination with the priority access model. The rationale for this preference is discussed below.

Operational timeframes

Given that the CMM is mandatory, the ESB anticipates a need to defer the introduction of the CMM to give market participants time to update their contractual arrangements or to allow a sizeable proportion of existing contracts to expire, ultimately diminishing the benefits given the urgent need for these reforms.

This need does not apply to the CRM as it gives market participants more flexibility as they adapt to the new regime, and an incentive to adapt as quickly as possible. As a result, the CRM delivers greater operational and emissions benefits and incurs lower legal implementation costs.

On the other hand, AEMO's costs to implement the CRM are bigger than for the CMM and are incurred sooner. While bigger than the costs of the CMM, the estimated costs to AEMO of implementing the CRM are much lower than the ESB's earlier indicative estimates.

Overall, the mid-point of the high and low estimates of each model individually are very close – for the CRM alone it is approximately $240m NPV, compared to approximately $220m NPV in the CMM. Further, important qualitative factors also play a critical role in our recommendations.

In comparison to the CMM, the CRM distributes benefits between generators in a manner which more closely reflects the status quo arrangements. As a result, the CRM better avoids "winners" and "losers" among market participants arising from the reforms. Rather than creating winners and losers, the voluntary nature of the CRM creates a framework whereby market participants can choose to earn additional profits by participating in the CRM. To encourage investment, it is a common principle in public policy that regulatory interventions do not substantially disrupt the allocation of value between existing market participants. This is better achieved by the CRM. The disruption associated with a redistribution of winners and losers between existing market participants – particularly when this is based on a regulatory decision rather than commercial factors – may result in significant additional costs associated with the CMM.

The CRM has potential to reduce the cost of capital for generators, while the effect of the CMM on the cost of capital is more ambiguous. This may lower prices for consumers in the CRM design.

Investment timeframes

We have not identified any studies to demonstrate that the congestion fee would address more or less of the inefficiencies in the current arrangements than the priority access model – although the administrative challenges of calculating such fees are well known. As they are both targeted towards addressing the same regulatory failure, priority access and congestion fees deliver similar levels of efficiency benefits. There is no clear preference among stakeholders between the two models.

On balance, we prefer the priority access model for qualitative reasons. The administrative process to calculate congestion fees is inherently complex, and the priority access model addresses the risk that an efficient project is curtailed due to an inefficient subsequent connection that chooses to pay the fee. Consequently, priority access may have an advantage in terms of supporting and strengthening REZ schemes and is more likely to have a downward impact on cost of capital.

Enhanced information

Enhanced information has been assessed separately in this cost benefit analysis because it deals with a different market failure to the other options. Specifically, it deals with how information deficiencies about transmission infrastructure and its use may prompt inefficient decisions by market participants.

The ESB has worked with AEMO and EY to prepare an estimate of AEMO's implementation and ongoing costs for implementing enhanced information. With an estimated cost of $9.3 million in NPV terms, the ESB regards enhanced information as a no-regrets reform when compared to the scale of investment required to deliver the energy transition. Given that further work is required to settle the detail of the information to be made available, these estimates are necessarily high level, with range of uncertainty of ± 50%.

1 Structure of this report

This report outlines an analysis of the costs and benefits of reforms to change the way market participants, such as generators and battery storage, use transmission infrastructure in the National Electricity Market (NEM).

Cost benefit analyses of policy reforms identify:

- the market or regulatory failure which may justify reform
- a range of credible options to address the market or regulatory failure
- the costs and benefits of those options compared to current arrangements to inform whether reform should proceed and the choice of the preferred reform option.

In this document we present two separate cost benefit analyses relating to two different regulatory failures:

- **Part A** considers the regulatory failure of how market participants pay to use transmission infrastructure, and the costs and benefits of options to address this problem.
- **Part B** considers the separate market failure of how information deficiencies about transmission infrastructure and its use may prompt inefficient decisions by market participants.

Options to address the regulatory failure identified in part A are unlikely to be a solution to information deficiencies discussed in part B. Conversely, options to improve the information on which market participants make decisions will not address the market failure identified in part A. Cost benefit analyses involve comparing alternative options to address the same problem. It is for this reason that two separate cost benefit analyses have been provided in parts A and B.

PART A – Transmission access reform

2 The policy problem

The NEM is a wholesale electricity market in which market participants – buyers of electricity (typically large customers, electricity retailers and storage units) and sellers of electricity (typically generators and storage units) – transact.

The NEM is a zonal electricity market with five regions. There are five marketplaces designated under the rules, one in each region (which almost exactly follow the boundaries of Queensland, New South Wales, Victoria, South Australia and Tasmania). These marketplaces are at specific locations on the network within each region, known as the region reference nodes (RRNs). The locations of marketplaces often emerge where there is a concentration of supply (such as Brent Crude oil, in the North Sea of Europe) or at the intersect of transportation routes (such as the Henry Hub for natural gas in Louisiana). In the NEM, we understand the marketplaces were selected at locations of high demand for electricity: specific suburbs within the state capitals in all cases other than Tasmania, where the marketplace is George Town on the north coast (the point where electricity is exported to the mainland).

The price of electricity at each marketplace in the NEM is equal to the cost of consuming another unit of electricity *at that location*, i.e. the *marginal* opportunity cost at that location. This price is known as the regional reference price (RRP). Consequently, the “wholesale price of electricity in Victoria” is more precisely “the price for electricity at Thomastown (a suburb in northern Melbourne), as calculated by the change in the cost to meet demand of another unit of electricity at Thomastown”.

While much of the load is consumed at or near the marketplaces owing to the high proportion of Australia’s population and industry being in the state capitals, most generators and storage, as well as some load, are located remote from the marketplace. These locations have superior fuel availability, sunshine, wind, suitability for hydroelectricity or some other advantage. In order to be traded at the marketplace, the energy produced by the market participant must be able to make its way from its source to load using the transmission network.

One way of thinking of the policy problem is that generators do not face a price to transport their energy across the transmission network. In normal well-functioning markets, prices are used to ration a scarce resource. Prices rise until demand (at that price) is equal to supply. In this way, those that value the resource the most secure it, while those that value it least do not: an efficient outcome.

In a well-functioning electricity market, prices would be used to ration scarce transmission capacity to the lowest cost combination of generators given the congestion. Low-cost generators are willing to pay more to transport their electricity to the marketplace, because their low costs allow them to still make a profit selling their electricity even if they must pay a high price for transport. Higher cost generators are willing to pay less because their higher costs mean paying a higher price for transport might be unprofitable overall.

This is not what happens in the NEM. The key problem is that prices are not used to allocate scarce transportation (i.e. transmission services) because generators are not charged for transporting (transmitting) electricity. Without such a charge, all generators that seek to transport their electricity across the constrained part of the network compete to use the network by indicating they are willing to sell electricity at the lowest price allowed by the rules (the market floor price).

This chapter provides an overview of the policy problem. A more detailed explanation is set out in Chapter 2 of the Directions Paper.

2.1 The market design creates an externality with respect to congestion

The design flaw that is the subject of this cost benefit analysis is that market participants do not face the costs they impose on third parties when, as a result of their use of the transmission network, another market participant is curtailed. The flow of electricity across a network has operational costs caused by losses[3] and congestion. The current market design approximates the cost of losses using marginal loss factors but does not deal effectively with the cost of congestion.

As a result of these issues, market participants have incentives to act in ways which are inconsistent with economic efficiency. This design flaw can lead to participants making inefficient decisions on the location and nature of investments and to inefficient bidding. Inefficient bidding leads to inefficient operation of the system with higher costs and higher emissions. It creates an **externality**, where one party's actions have an unpriced impact on third parties. The inefficient costs are borne not by the party undertaking actions but by others, limiting the incentives on the party taking the action to ensure costs are minimised. In turn this can lead to higher fuel costs, higher capital investment costs in generation, storage and transmission infrastructure and higher risks for market participants. The specific inefficiencies arising from this externality are explored in section 2.3 below. Externalities are a type of market failure that is commonly used to justify regulatory change.

When costs are externalised, what is most privately profitable for a market participant may not be most beneficial for the total system, because the market participant is not facing the full costs of its actions. In this case, market participants are indifferent to the cost of any additional congestion they are causing on the network. Instead, the cost of congestion is borne by other market participants in that there is less transmission capacity available for them to use. As a result, the third parties miss out on revenues from selling electricity or benefits from consuming electricity. This not only increases total costs, but also increases risks as market participants are poorly placed to manage the costs that fall on them as a result of other market participants' actions. These risks in turn flow through to an increase in the costs of capital, all else equal increasing prices or reducing reliability for consumers.

2.2 What are the consequences of poor congestion management and pricing?

The Australian Energy Market Operator (AEMO) runs an algorithm to determine which market participants trade at the marketplace. When there is more transmission capacity than is required at any given time, this process is simple: AEMO selects the generator which offers to sell their electricity at the lowest cost, and then the next cheapest, and so on in ascending order until demand is met (and met at lowest cost).

However, the transmission network has limited capacity and on many occasions the algorithm needs to optimise dispatch when the transmission network is "congested". When this happens, some generators which offer their generation at relatively low prices and so without the congestion would be dispatched must be "constrained off" – not generate. To meet demand, some other generators that offered at relatively higher prices, who are located elsewhere and who are in a less congested part of the network, are dispatched instead. The increase in costs arising from using a more costly generator is known as the "cost of congestion".

In normally functioning markets that are capacity constrained, when demand exceeds supply at a given price, prices rise until demand is reduced to equal the fixed supply. For example, customers must pay a high price to secure hotel rooms at peak times.

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3 Losses relate to a separate technical phenomenon – it is the energy that never makes it to its destination because it dissipates in the form of heat along the transmission wires. Losses are beyond the scope of this reform.

In contrast, in the NEM, generators that are dispatched do not face the cost of this congestion. Rather, they receive the same price irrespective of whether they are in a congested location. Instead, generators that are constrained off as a result of congestion face these costs in the form of reduced output. Generators are a “customer” of the transmission network, as they use transmission services to get their product to the marketplace. Because they do not face the cost of congestion, they are incentivised to bid in a way that is inconsistent with reducing total system costs. This is the underlying cause of the inefficiency.

Of course, many parts of the network are not congested. In this case utilising the unconstrained network does not preclude other market participants. As a result, the cost of congestion is zero, and the price to use the transmission network should also be zero – as it currently is. The inefficiency only arises in locations and at times of congestion.

That said, congestion is common in all regions of the NEM, and for good reason. Building transmission capacity is expensive and imposes costs on the communities that the transmission lines run through. If not carefully targeted, the cost of building transmission can very often exceed the reduction in the cost of congestion. Just like we do not have unlimited numbers of hotel rooms because building hotels is expensive, we also do not have unlimited transmission capacity.

2.3 What are the inefficiencies?

Broadly, the inefficiencies occur over two time periods: operationally and over the investment timeframe. The inefficiencies arise for generators, load, storage units and transmission. There are many specific ways in which inefficiencies can arise, with the most significant outlined here.

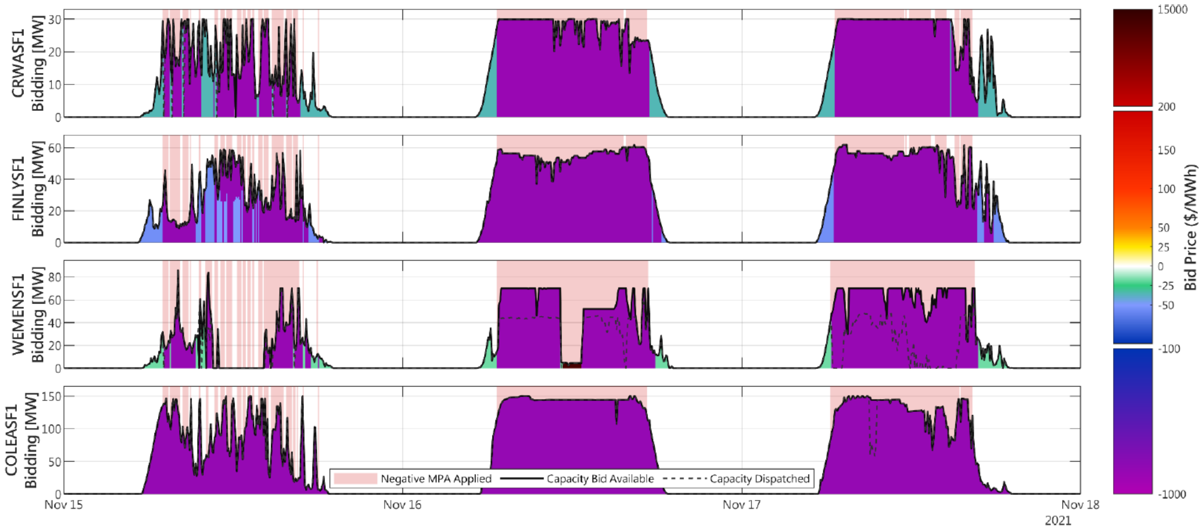
2.3.1 Operational inefficiencies

When congestion occurs, generators in the constrained part of the network compete to use the network by indicating that they are willing to sell electricity at the lowest price allowed by the rules (the market floor price of -$1000MWh). It is profitable to do this because generators are paid the regional reference price (RRP), not their bid price. A constrained generator knows that its bid will not set the RRP, since otherwise, the constraint would not have bound.

Faced with identical bids, the dispatch algorithm selects the generators that by virtue of their location utilise the constrained route across the network the least. This is not necessarily the generators with the lowest fuel costs. Some low-cost generators (which are also often zero emission generators) are not able to be dispatched because some higher cost (and often higher emission) competitors are dispatched instead.

Constrained generators have a strong incentive to undertake disorderly bidding on congested parts of the network – if they do not, their competitors, who are disorderly bidding, will be dispatched instead of them. Figure 2 provides an example of solar generators bidding towards the market floor price when a constraint bids.

Figure 2 Bidding behaviour in the presence of a binding constraint



Source: The Australian National University, Battery Storage and Grid Integration Program

AEMO's algorithm determines the dispatch based on generators' bids, not their underlying costs. As many generators are bidding at -$1,000/MWh, the algorithm does not select the generators with the lowest underlying costs: it instead selects the generators that, by virtue of their location, utilise the constrained route across the network the least. This way, the maximum amount of electricity with a notional cost of -$1,000/MWh can be traded at the marketplace.

For example, suppose two generators utilise a constrained part of the network. Generator 1 is a variable renewable generator with zero fuel costs. By virtue of its location on the network, all of its output flows across the constrained part of the network. Generator 2 is a coal plant with high fuel costs and emissions. As it is at a different location on the network, for each 1MWh it generates only 0.5MWh uses the constrained route, with the other 0.5MW utilising other unconstrained routes to the marketplace. Because both generators bid at -$1,000/MWh, the notionally cheapest combination of resources (from the perspective of the algorithm) is to maximise the use of generator 2 and minimise the use of generator 1, as generator 2's output contributes half as much to congestion.

But of course, the electricity does not really cost -$1,000/MWh. The bid reflects the fact that the generators do not face the cost of the congestion they cause. This behaviour has the effect of increasing the total costs of dispatch: some cheap generators (which are also typically zero emission generators) are not able to be dispatched because of strategic bids made by their higher cost (and typically higher emission) competitors.

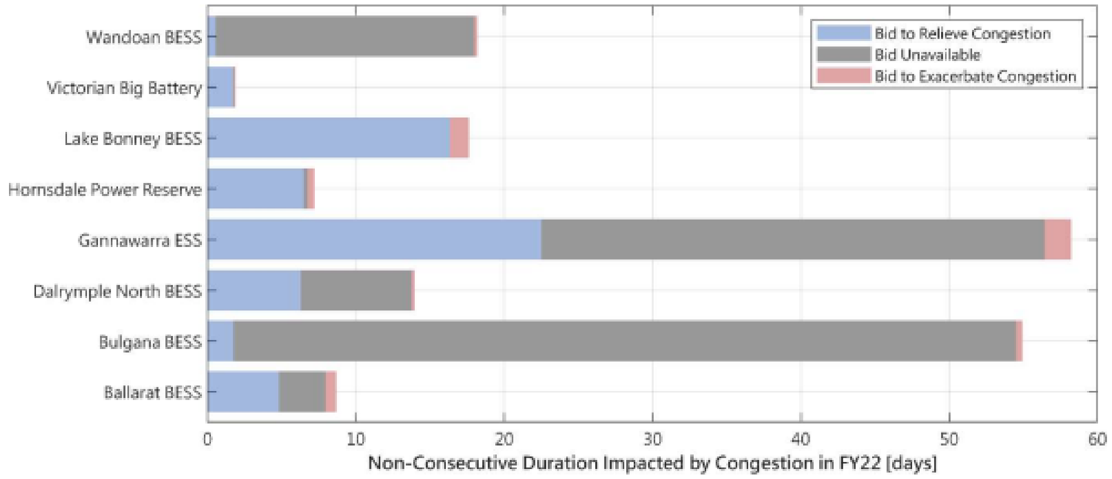
Some market participants, by virtue of their location, alleviate transmission congestion. For example, scheduled load, including storage when acting as load, can relieve points of congestion and allow relatively cheap electricity to flow in the prevailing direction, *reducing* total system costs.

A charging storage unit should be paid for the value it creates when it reduces congestion by soaking up cheap renewable energy. This is an example of a *positive* externality: the full *benefits* of the load's or storage unit's actions are not reflected in the price. In turn, the storage unit or load may choose not to consume, despite the benefits to society as a whole – because the private benefits to them given the price they would need to pay – is too high.

A discharging storage unit is subject to the same negative externality as a generator. Consequently, it can be incentivised to act in an inefficient manner: generating and reducing the output of VRE generators, instead of storing additional renewable generation for future use and being paid to do so.

Analysis by the Australian National University (ANU) Battery Storage and Grid Integration Program provides evidence that grid scale batteries bid to exacerbate congestion from time to time – although they also bid to alleviate congestion (e.g. when the RRP is low) or bid unavailable (e.g. if they are energy constrained). Bids to exacerbate congestion are more likely to occur when the RRP is high, and hence the value of the curtailed energy is high.

Figure 3 Utilisation of 8 grid scale batteries in the NEM for congestion relief during FY22



Source: ANU Battery Storage and Grid Integration Program.[4]

The ANU notes that "while some level of spillage and curtailment is widely acknowledged to be part of an efficient high VRE grid, it is also clear to see how the congestion relief capability of existing storage assets is potentially being under-utilised in the current market structure."[5]

Storage should pay a lower price to consume electricity when this facilitates the flow of cheap, renewable energy across a constrained part of the network. In today's energy market, storage can be incentivised to inefficiently generate electricity because it avoids the congestion costs. Instead, it exacerbates congestion and reduces the cheap renewable generation available. Storage can therefore be incentivised to act in the wrong manner: generating and constraining off renewables, instead of storing additional renewable generation to alleviate congestion now and use later.

If congestion is priced, arbitrage opportunities increase for batteries in congested locations.

2.3.2 Investment inefficiencies for generators, storage and load

These various problems flow through to investment incentives. As noted above, if the dispatch algorithm is unable to differentiate between constrained generators based on price because they all have bid to the market price floor, it will instead select the generator(s) that utilise less of the constrained network compared to their competitors. A generator can locate in a particular location and be dispatched, displacing existing generators who use more of the constrained network but would previously have been dispatched. It would be more efficient to invest in uncongested parts of the network. The new generator is largely *offsetting* ("cannibalising") the output of an existing cheap and low emission generator. But the private benefit to the investor is substantial: it has avoided the cost of the congestion it has exacerbated.

4 ANU,https://www.datocms-assets.com/32572/1673412922-bsgip-response-to-transmission-access-reform-directions-paper.pdf, December 2022.

5 Ibid, page 8.

Instead, the cost of the congestion is externalised onto incumbent market participants who are constrained off. In turn, this creates risks for investors which ultimately increases prices for consumers. While new investors might – in the first instance – be the party who cannibalises the output of its predecessors, over time they too risk subsequent investment cannibalising them.

As these investments often result in little *additional* cheap and low emission energy being generated as a result of these investments, more investment will be needed to meet customer needs. Alternatively, otherwise efficient new investment may not proceed in a particular location because, despite being cheaper than its competitor, it is unable to be dispatched.

Less efficient use of the network and dispatch of plant under the current arrangements causes higher emissions than could be achieved with the same plant mix and access reform. In the absence of reform, more investment in transmission, generation and storage will be required to meet governments' emission reduction targets.

Similarly, flexible load is also incentivised to locate inefficiently, or not at all. Imagine a hydrogen electrolyser which, by virtue of its location near renewable generators, would, by consuming electricity, allow more renewable energy to be dispatched. Absent the externality, it should be paid to do so. But because the load faces the RRP irrespective of whether it is helping to alleviate congestion, its business case to locate there (or indeed anywhere) has been diminished.

Storage also faces distorted incentives. Its business case to locate in areas that, by consuming, alleviates congestion and enables more renewable generation, is diminished. Businesses may instead choose to locate elsewhere, given the price signals they face.

This will mean that we need more renewable generation capacity, or more transmission capacity, or more batteries, for a given level of reliability and emission reductions. An inefficient fleet of generators will in turn impact the operation of the system – changing the combination of generators which are utilised in any given time.

2.3.3 Investment inefficiencies for transmission

Transmission expenditure is also negatively impacted by poor congestion management, since poorly located generation can drive a need for more transmission investment than would have been required if the generators located elsewhere.

The Integrated System Plan (ISP) is AEMO's best estimate of the total least cost development of the system into the future, subject to meeting reliability and emission reduction requirements. As a cost minimisation exercise, the ISP does not take account of the actual incentives – in operations and investment – that market participants face. In effect, it assumes that market participants invest and bid as if the costs of congestion were fully internalised into prices. As a result, via the ISP, we are planning and making investments in a transmission system that is optimised for what market participants *would do* were there no regulatory failure, not what they are *actually incentivised to do* given the existing regulatory arrangements.

Over time, as market participants make investment and operational decisions that differ from the ISP's expectations because of the perverse incentives they face, subsequent iterations of ISP will adapt. At each iteration the ISP will consider the recent investments of market participants, and project from that point in time the new ideal transmission expenditure path – once again assuming efficient behaviour on the part of market participants going forward.

While this approach identifies the optimal development path given the state of the power system at a point in time, over time it can result in excessive transmission expenditure that would not be needed if market participants located and operated efficiently.

3 Policy options

The ESB, in consultation with stakeholders, has developed four options to address the policy problem identified in Chapter 2. Given that the regulatory failure reflects the externality associated with costs of congestion, the policy solutions seek to internalise those costs and hence remove the perverse operational and investment incentives on market participants.

Two options seek to address operational inefficiencies, but do not directly address capital expenditure inefficiencies and related risk. Two options seek to address capital expenditure inefficiencies and related risks, but do not address operational expenditure inefficiencies.

Table 2: Options for transmission access reform

Operational timeframes	Investment timeframes
Congestion relief market (CRM)	Congestion fees
congestion management model (CMM)	Priority access

These options can be combined. They are not mutually exclusive. Indeed, the priority access must be combined with either the CRM or CMM model – as a standalone option it is unlikely to be a credible option to maximise net benefits, as discussed in section 3.4.2.

The ESB is separately considering whether enhanced information relating to congestion and spare transmission capacity should be made available to market participants and other stakeholders, as discussed in part B of this report. Well-functioning markets require good information. Insufficient or misleading information to inform decision-making is a market failure that can justify regulatory intervention. However, this is not the market (or in our case regulatory) failure identified in section 2.1, and so better information will not address the issue identified.

Each of the options are discussed below in order. For each option, an overview is given, followed by the main benefits of each option (which differs by option) and the limitations.

3.1 Congestion relief market

3.1.1 Overview of option

The ESB CRM design is based on the modified version from the Clean Energy Council (CEC).[6] In a "congestion relief" market, market participants would be rewarded for changing their dispatch amount to move towards a more efficient dispatch outcome. Under this design, the CRM clears adjustments in dispatch quantities, compared to the dispatch outcomes of the energy market.

While the existing "energy" market and the new "congestion relief" market would both run within each 5 minute dispatch interval using bids submitted in advance, it is simpler to think of them as sequential. Market participants receive their initial dispatch target as per the existing market design, before subsequently trading to adjust their targets in the second CRM. Through this second market, generators could become a:

- **CRM seller**. A generator who wishes to increase output above its initial dispatch target can sell energy in the CRM. In most cases, energy traded in the CRM will be cheaper than the RRP.
- **CRM buyer**. A generator that is willing to reduce output below its initial dispatch target does not lose any RRP revenue, but it now pays to buy replacement energy from the CRM. The net

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

effect of these payment structures is that a generator that reduces its energy output profits from avoided costs.

Similarly, flexible loads including storage could become a CRM buyer by offering to consume more energy in the CRM. This would only be worthwhile for the flexible load/battery if the price they pay to consume in the CRM is lower that the RRP.

3.1.2 How the option enhances economic efficiency in operational timescales

The CRM should enhance economic efficiency. Relatively high-cost generators that were initially dispatched in the existing energy market would be willing to reduce their output for a relatively low price – because they could be more profitable by avoiding costs associated with generating and instead pay a lower cost generator for its output. Conversely, some low-cost generators that were not fully dispatched in the existing energy market would be willing to sell more energy because they can still be profitable selling energy at the CRM price.[7]

Generators would have the opportunity to earn additional profits via the bids made in the second market. As in other workable competitive markets, the CRM price would rise to the level required to balance supply and demand at a given point on the transmission system, as revealed by market participants' bids.

The outcome – subject to some important caveats discussed in section 5.2.4 – would be that all profitable trades for each counterparty should enhance economic efficiency by reducing the cost of generation or increasing the benefits of consumption. Conversely, all trades that enhance economic efficiency are profitable for both counterparties and so could be expected to proceed. This is consistent with the general principle that workable competitive markets (which do not exhibit market failures) efficiently allocate resources.

Generators would not have an incentive to engage in race to the floor bidding in the CRM because by bidding disorderly they are offering to sell energy in the CRM at a very low price. In the CRM, market participants pay/receive the local congestion relief price (the CRM price).

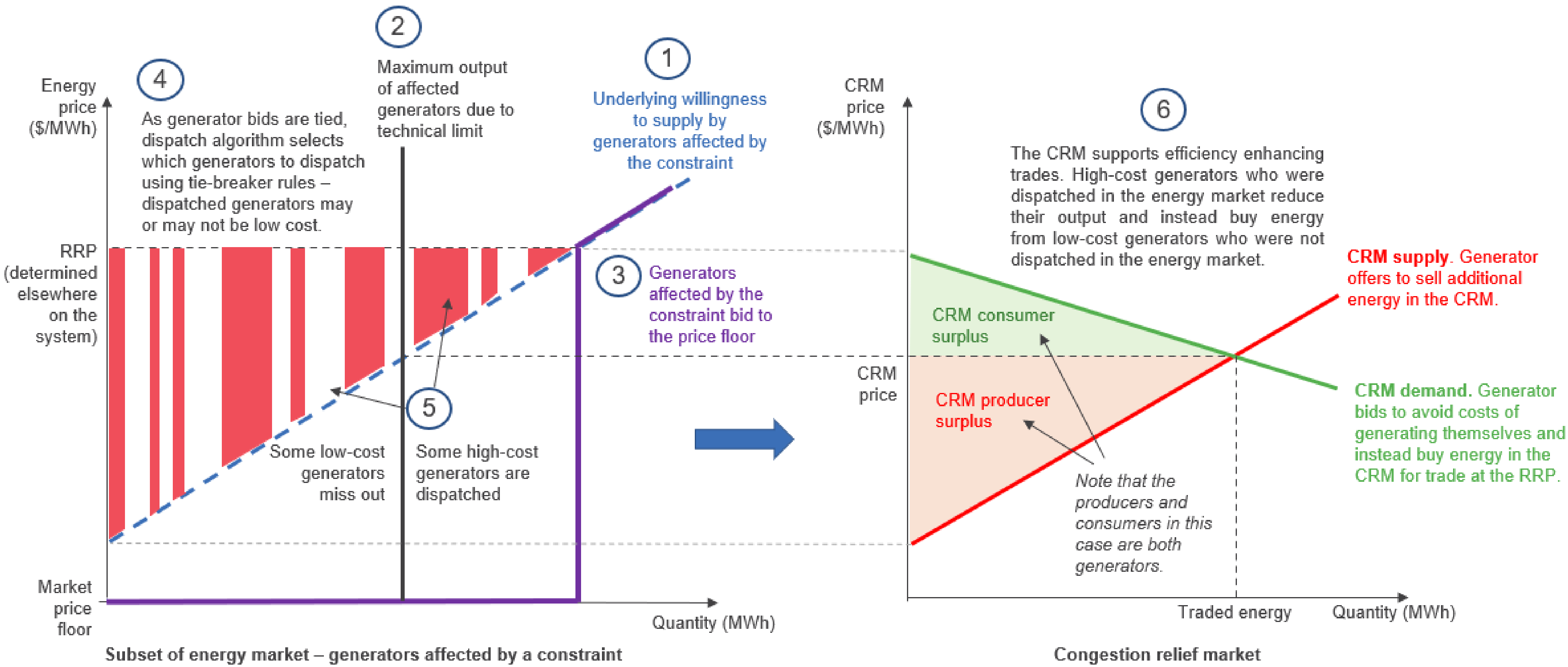
Trade in the CRM (and energy at the marketplace) would be voluntary. If the CRM price is too low for the seller or too high for the buyer, the trade will not go ahead.

CRM prices would be equal to marginal opportunity costs – the foregone benefit to the next market participants who were not able to be dispatched, as revealed by their bids. As CRM prices equal the marginal opportunity costs imposed on the system as a whole, the optimal outcome for the market participants is the optimal outcome for the system as a whole.

7 A complication in this simple description is that market participants use constrained parts of the network by different amounts (or not at all) depending on their location. Market participants relatively remote from the constraint use it less than those closer to it. The amount each market participant uses a particular part of the network is known as its "constraint coefficient" (also known as the "participation factor", "shift factor" or "contribution factor"). The CRM automatically accounts for this when determining the trades, much like an exchange rate in currency markets. These complications are discussed in the ESB's paper on Modelling the congestion relief market (February 2023). Regardless, the basic principles of the CRM are the same: energy is traded between market participations at a price set in the market.

This discussion is summarised in the supply-demand diagram in Figure 4 (with a focus on generators, rather than load or storage, for ease of explanation).

Figure 4 CRM high level concept



For simplicity, this figure focuses on the most straightforward and intuitive example of CRM trading, which is the case where there are differences in generators' underlying costs. The CRM also enables trading in other circumstances, such as when a generator with a low value PPA is dispatched ahead of a generator with a high value PPA.

3.1.3 How the option allows generators to manage risk in operational timescales

Compared to current arrangements, this option allows generators to better manage the risk of not being dispatched in the energy market.

Under current arrangements, a generator that is not dispatched in the energy market as a result of congestion effectively also loses the opportunity to earn profits from selling energy at the marketplace. Instead, generators that were not dispatched in the energy market at the level they wanted have a new opportunity to sell extra energy in the CRM. Generators would do so as long as they are profitable selling energy at the CRM price. Otherwise, they would not trade in the CRM and would be no worse off than under current arrangements. Effectively, the reform would provide generators with a tool to manage the risk of not being dispatched in the energy market by trading in a second market to reduce the impact that this has on their profits.

However, as discussed below, while this option allows generators to better manage risk, it does not, on its own, remove the risk itself.

3.1.4 Limitations of the option in investment timescales

This option, on its own, does not directly or fully address the investment inefficiencies or the related risks, as discussed in section 5.3.4.

Under the CRM, generators continue to be able to impose congestion costs on others because the initial dispatch in the energy market is allocated as per the existing arrangements. Market participants would continue to have an incentive to locate inefficiently. By bidding disorderly in the existing energy market, they can maximise their initial dispatch allocation, which they can then use for their own purposes (for free) or trade (at a profit) in the CRM. The incentive to not disorderly bid only arises in the subsequent CRM, which promotes operational efficiency, not investment efficiency. In the extreme, under the CRM alone a new generator may, by its location, be dispatched at the expense of an existing generator which is (initially) constrained off. It can then avoid costs of generating by buying energy from the generator which was already there, but at a lower price than that generator was previously receiving. This may be profitable due to constraint coefficients (see footnote 7).

This creates risks for market participants. While the new generator may initially do the cannibalising, over time it may find its output is curtailed by yet more generators as they subsequently connect.

3.1.5 Impact on market participants relative to the status quo

Under the CRM, the initial dispatch outcome is via the existing energy market, with the existing incentives to disorderly bid. The CRM preserves the initial allocation of access, and in addition, provides market participants with an option to increase their profits by buying energy from a cheaper source, rather than generating it themselves. This avoids creating “winners” and “losers” among market participants as a result of the reforms.

3.2 Congestion management model

3.2.1 Overview of option

In this option, there is a single “energy” market, but market participants affected by congestion would pay a charge that reflects the cost of congestion and market participants that relieve congestion would receive a payment that reflects the avoided cost of congestion.

Under the CMM, the revenue recovered via the charge is then re-divided and repaid to the market participants in the form of a rebate. This can be done in many ways, but the general principle is that it should not impact the bidding behaviour of market participants (i.e. the revenue is not allocated on the basis of bids or outcomes influenced by bids). A possible option is to re-allocate revenues on the basis of a combination of how much a market participant uses (or alleviates) congestion (its "constraint coefficient") and its real-time availability to generate (or consume) electricity (its "available capacity" as defined in the National Electricity Rules).

The rebates partially or fully offset the cost of congestion or can be used as compensation when a market participant is curtailed, resulting in forgone revenue of not selling energy (or foregone benefit of not consuming energy).

Under these arrangements, market participant bids can be expected to more accurately signal their costs, as the rebate they receive is independent of their bids.

Providing the general principle discussed above is met, the efficiency gains from the model in operational timeframes will be achieved regardless of the precise mechanism which divides the revenue between market participants. The precise method for reallocating the revenue impacts winners and losers but not operational efficiencies. Given this CBA is primarily focused on efficiency gains, the precise re-distribution method is not a focus of this CBA. Wealth transfers are discussed in section 4.2.2.

3.2.2 How the option enhances economic efficiency in operational timescales

This option directly addresses the operational inefficiencies of the existing market by determining and settling market participants at the price that reflects the cost of congestion given market participants bids.

The underlying driver for the benefits of the CMM in operational timescales are identical to those from CRM: low-cost generators would be willing to pay a relatively high charge in the presence of congestion and vice versa, resulting in an overall dispatch outcome which is efficient.

Market participants would no longer have an incentive to bid disorderly because doing so risks paying a very high charge. Instead, they are incentivised to bid in a manner which more closely reflects their underlying costs, which enables the dispatch algorithm to find an efficient solution when there is congestion.

3.2.3 How the option redistributes risk among participants

Unlike current arrangements (and the CRM), the CMM redistributes the value among participants in the form of rebates.

While this could be done in different ways, the option of calculating rebates on the basis of a pre-determined metric would result in a different allocation of the value compared to current arrangements. For instance, if the pre-determined metric allocated rebates based on constraint coefficients and availability, value would be shared across participants, whereas current arrangements give rise to 'winner takes all' outcomes.

This would redistribute risk among participants, creating 'winners and losers' relative to the status quo. A participant that would have not been dispatched under current arrangements would receive a rebate under the CMM, therefore this option would reduce the risk arising for this participant when constraints bind. A participant that would have been dispatched under current arrangements would also receive the rebate.

However, this would be lower than the value of dispatched energy that the participant receives under current arrangements, because under the rebate system that value is shared with other participants. For this participant, when constraints bind the CMM introduces risk that was not present under the current arrangements.

This applies in operational timescales but also in investment timescales, because, as discussed below, the CMM on its own does not address investment inefficiencies. As more participants site in a congested area, the rebates for all incumbents are increasingly reduced.

3.2.4 Limitations of the model in investment timescales

As with the CRM, the CMM does not directly and fully address investment inefficiencies in the current arrangements, nor the associated risks.

While in the CRM this is because the starting point for CRM trading is the initial dispatch in the energy market, in the CMM it is because the rebates are provided for free.

Market participants are in effect subsidised to locate in parts of the network which exacerbate congestion, because via the receipt of the rebate they do not face the full cost of the congestion they cause. Instead, some of the cost is borne by other generators, whose rebates are reduced. Similarly, market participants are penalised for locating where they alleviate constraints, because they do not receive the full benefits of the congestion they alleviate (with some of the additional left-over revenue arising from their actions being rebated to other market participants).

The resulting inefficiencies are therefore similar to the CRM. The private benefit of an investment may be positive because the investor has avoided the full cost of the congestion it has exacerbated because it knows it will receive a rebate. But the overall benefits of the investment as a whole may be negative, with the difference between the private and social benefits being borne by other market participants through a reduction in their rebates – in turn increasing their risks.

However, while the inefficiencies are conceptually similar, they may not be the same size. Many of the rebate allocation methods being considered by the ESB involve *sharing* ("pro rating") rebates between parties, with each party getting some revenue. Consequently, the newly connecting party may bear some of the cost of the congestion it causes, even if much is allocated to others – a *partial* solution to the investment inefficiency problem. In contrast, the initial dispatch under CRM is in accordance with the existing energy market – those in favourable locations bear *none* of the costs of the congestion they cause (at least until they too are cannibalised), while others bear all the cost of congestion.

3.2.5 Impact on market participants relative to the status quo

While the CMM rebate allocation methodology – if designed appropriately – will not affect operational efficiency, differing possible designs redistribute revenues to market participants in different ways, that also differ from that of the status quo.

Some rebate allocation approaches will more closely align with the status quo outcomes than others. However, none of the approaches exactly replicate the status quo method. As a consequence, there are likely to be market participants who are "winners" from these reforms at the expense of "losers" compared to the status quo arrangements (and also compared to the CRM). Which parties win or lose is a function of the regulatory decision on the CMM's allocation metric.

3.3 Congestion fee

With a congestion fee, market participants would be charged an additional fee reflecting the expected cost of congestion they will cause. The fee would be determined upfront (although it may be paid over time). The fee would be in addition to the existing *connection* fee, which reflects the cost of connecting *to* the network. The fee would be determined by a central agency (e.g. TNSP with AER oversight).

3.3.1 How the option enhances economic efficiency in investment timescales

Under the status quo arrangements, there is an implicit subsidy for market participants to locate in areas that are congested, because they do not bear the full cost of the congestion they cause. As noted above, neither the CRM nor CMM directly and completely address this problem. Instead, some (with the CMM) or all (with the CRM) of the costs are borne by other market participants. Similarly, market participants that alleviate constraints are penalised, with the benefits of alleviating congestion received by others.

These arrangements may promote inefficient investments that are privately profitable but not best for the system as a whole because the full costs of actions are not being borne by those taking the actions. Similarly, it may dissuade otherwise efficient investments from occurring because they are not privately profitable despite being best for the system as a whole.

The rationale for the congestion fee is conceptually simple. By determining a charge for market participants upfront, the externality is internalised. This should incentivise more efficient investment.

While conceptually simple, determining the fee is likely to be complex. That said, it is likely to be an improvement on the current arrangements, given the price is currently set at zero.

3.3.2 Why the congestion fee does not address operational inefficiencies

As a one-off fee determined upon connection, the congestion fee alone would not address operational inefficiencies. Regardless of the fee, market participants would continue to have an incentive to disorderly bid in order to maximise their access to the transmission network, in turn meaning that the lowest cost combination of generators do not generate.

3.3.3 Limitations of the fee with regard to risk management

Even assuming that the fee is appropriately set, it only partially addresses the risk to existing market participants from being curtailed as a result of subsequent generator entry.

While the fee would discourage inefficient investment in congested areas, it is still possible that a market participant could choose to locate in a particular area despite facing the full, internalised costs of the congestion via the congestion fee. The new generator may then cannibalise an existing generator's ability to be dispatched.

3.4 Priority access

This model, taken by itself, would provide investors with greater certainty but at the cost of efficiency. The ESB proposes that the priority access model must be combined with either the CRM or CMM. Whether combined with the CRM or CMM, some market participants are provided priority "access" to the transmission network but would compete at the margin for incremental physical dispatch.

In combination with the CRM, priority is given effect by changing initial dispatch outcomes in the energy market. When bids are tied at the price floor, market participants with priority would be prioritised in the energy dispatch over those without priority, receiving more access which they could then sell to others or use themselves.

In combination with the CMM, priority is given effect by changing the methodology of the allocation of the rebates. Those with priority would receive bigger rebates.

Precisely which market participants are provided priority access, and for how long, varies under various sub-design choices that are still being considered by the ESB, trading off matters such as implementation complexity and the competing interests of incumbents and newcomers. For example, market participants might be provided priority in chronological order of connection (or some other event in the connection process) or in batches, or if they make payments. Incumbent market participants at the time of the introduction of the reforms might all be provided "priority" access compared to newly connecting market participants, but these rights might not always result in dispatch given some parts of the network are currently congested. Generators connecting to a jurisdiction's renewable energy zone (REZ) may be provided priority access over those that do not, perhaps because they have paid a fee to join the REZ. New priority rights may be created when transmission infrastructure capacity is increased, or when incumbent generators exit the market, freeing up some transmission capacity for others. This CBA will not attempt to determine the relative costs and benefits of these various sub-options, but instead provides a generic assessment of the priority access option.

3.4.1 How the option improves risk management

The priority access model provides market participants with more certainty about their initial dispatch outcome (CRM) or rebates (CMM). It lessens the chance of their access being cannibalised by a newly connecting generator.

For example, if generators are allocated priority in strictly chronological order of connections, then each generator knows that it cannot be cannibalised by subsequent connecting generators. Each subsequent generator will bear a greater share of the cost of the congestion it causes and is unable to externalise those costs onto incumbents.

Generators considering connecting in a congested part of the network may not receive particularly valuable priority rights – because incumbents hold the rights instead (if priority is based on incumbency). These prospective generators may face the prospect of lower access to market for the period that priority access is allocated to others. But the investor would be aware of these risks at the time of connection. If these risks are too high, then the investor can consider connecting in a less congested area of the network, where valuable priority access is still available and the subsequent connection by another generator cannot impact their exposure to congestion risk.

3.4.2 Model requires CRM or CMM to avoid disrupting operational efficiency

Were the priority access model to be implemented on its own (i.e. without also implementing either the CRM or CMM), dispatch efficiency may not be improved, and could even be diminished versus the status quo arrangements.

Imagine a situation where two generators with identical and low costs both wish to be dispatched, and both partially utilise a congested part of the network. Under the status quo arrangements both would be incentivised disorderly bid and the algorithm would maximise the generator which by virtue of its location utilises the congested part of the network the least for each unit of energy it produces (with more of its generation taking other, non-congested routes to the marketplace). In this way, more generation which notionally costs -$1,000/MWh are dispatched. In these specific circumstances – notably that the generators have identical and low costs – this is the efficient outcome in operational timeframes.

In contrast, were the priority access to be implemented alone, the generator with priority access would be dispatched first. If this happened to be the generator which utilised the congested part of the network more, the total amount of low-cost generation able to be dispatched would decrease, increasing the total fuel cost to meet demand. This is less efficient than the status quo. It is for this reason that we do not consider that the priority access model alone is a credible option to maximise net benefits.

In contrast, the priority access model in combination with the CRM or CMM does not diminish efficient use of the transmission network in operational timeframes:

- Under the CRM, the initial dispatch outcome via the energy market is not efficient due to the disorderly bidding, and the subsequent CRM trading adjusts these outcomes to deliver an efficient result. The priority access model merely alters the initial allocation. Regardless of this different starting point, the CRM is expected to re-allocate dispatch outcomes efficiently.
- Similarly, under the CMM, the priority access model changes the allocation of rebates, but market participants will no longer have an incentive to disorderly bid because doing so risks exposure to a high charge.

3.4.3 A substantial – but still only partial solution – to investment efficiency

The priority access model limits the ability of newly connecting market participants from passing the costs of congestion that they cause onto *incumbent* market participants, and in this respect is likely to represent a significant improvement on the status quo.

However, some costs may be passed on. Those connecting in *currently* uncongested areas of the grid, but where the level of congestion is expected to increase in the future, would receive free priority rights over *subsequent* connecting market participants. This may incentivise generators to connect in parts of the grid that – by virtue of that location – "uses" a large amount of the transmission infrastructure which is expected to become congested in the future, when other generation locations would use less of the infrastructure and so allow more new generation to access the market overall. The result could be a level of investment inefficiency.

One resolution to this issue is that in areas of the grid in which there is likely to be a large amount of new demand for transmission access from newly connecting generators (e.g. REZs), priority rights are auctioned off. The rights would be allocated to the party that values them most highly. Those areas that are already congested are unlikely to prompt significant investment given that the costs and risks of congestion are borne under the priority access model by the newly connecting party – and at any rate the priority access model automatically internalises most of the new cost of congestion in congested areas.

3.5 Implementation timeframes associated with the options

Given the complexity and impact on market participants of the proposed transmission access reforms, a significant effort is required to implement them. As well as changes to IT and business systems, there is a need for comprehensive stakeholder engagement to ensure that market participants understand and adapt to the changes to the market design.

The ESB engaged consulting firm EY to assess the likely implementation cost on AEMO of the CRM, priority access and congestion fees. As part of this work, EY broke down the system impacts and provided an indicative implementation timeline for each of the reform proposals based on complexity ratings that were developed as part of the NEM2025 Integrated Regulatory and Technology Roadmap.

Given that further work is required to settle the detailed design of these options, these estimates are necessarily high level, based on information available at the time.

The final outcome will be influenced by a range of factors including: the detailed design of the final models, any unforeseen technical challenges that may emerge as part of the detailed design and implementation process, interdependencies with other decision-making processes required to implement the reforms, and the broader portfolio of concurrent systems changes associated with other energy market reform processes.

Subject to these caveats, our indicative expectations regarding the scope of the implementation task, and likely timelines, are set out below.

Table 3: Factors affecting implementation timelines by option

Model	Implementation task
CRM	The CRM has been assessed as a 'very large' complexity and has an estimated delivery timeframe (from project delivery initiation to effective date) of 42 months. This is on the basis that: • The overall duration for implementation includes standard times for development and consultation for procedures and high-level implementation design with industry (approximately 18 months duration). • The system and process changes are assumed to impact many systems including mission critical systems, functions (NEMDE), high volumes of data, and represents a large scale of change with extensive industry consultation and involvement (approximately 18 months duration). • Comprehensive industry testing and market trial will be required (approximately 6 months).
Priority access	The incremental changes to CRM that would be required to implement the priority access variant have been assessed as a 'medium' complexity. The queue management system is assumed to require a separate and new system and there is potential for a high impact on NEMDE depending on the number of queue positions. Additionally, the auction system will require a new build. Because the system changes required for priority access are incremental to the CRM, implementation dates could be aligned such that the two initiatives are delivered in parallel.
Congestion fee	The congestion fee variant has been assessed as a 'small' complexity in terms of effort on AEMO's part. This is on the basis that TNSPs would be responsible for calculating and collecting the congestion fees and so the impact on the AEMO's system and the website in particular is expected to be low. Although no new AEMO systems are required, the anticipated changes required by TNSPs and market participants, and the high level of consultation that would be required, means the timeframe for a 'medium' complexity initiative has been applied. Accordingly, it has an estimated delivery timeframe of 19 months. It has also been assumed that this could be implemented simultaneously with the CRM so as not to add an additional 19 months to the timeline.
CMM[8]	The CMM's mandatory nature, coupled with the significant wealth reallocation effect it is likely to have on existing participants, implies the ESB would expect it to be necessary to defer the implementation so as to give market participants time to update their existing contracts. Given the duration of the current portfolio of PPAs including some older long-term PPAs, we would expect to defer the introduction of the CMM to 2030.

8 Estimates for the CMM implementation task and likely timeframes were prepared by the ESB, taking into account earlier work undertaken as part of the Post 2025 market design process.

Model	Implementation task
	The CMM requires changes to AEMO's settlement systems. It is not expected to require changes to AEMO's dispatch systems since market participants continue to only submit energy bids to AEMO. Instead, the changed treatment in settlements affects market participants' incentives as they bid into the energy market. However, market participants will need to amend their business and IT systems to enable them to: • factor in changes to settlement, • forecast prices at which dispatch is likely to be traded between participants, • buy/sell dispatch from/to other market participants; and • interface with other market participants to facilitate any trades.

Based on these factors, we expect the timing for the implementation of the options to be as follows:

Table 4: Expected implementation year of different reform options assuming final rule changes are in place by June 2024

Policy option	Minimum implementation period	Earliest operation
CRM	42 months	January 2028 onwards*
CMM	To 2030	January 2030 onwards
Congestion fee	19 months	January 2026 onwards
CRM + Congestion fee	42 months (congestion fee 19 months but can be developed in parallel)	Congestion fee: Jan 2026 onwards CRM: January 2028 onwards*
CMM + Congestion fee	To 2030 (congestion fee 19 months but can be developed in parallel)	Congestion fee: Jan 2026 onwards CMM: January 2030 onwards
CRM + Priority access	42 months (priority access 19 months but can be developed in parallel)*	January 2028 onwards*
CMM + Priority access	42 months (priority access 19 months but can be developed in parallel)	January 2030 onwards

*Notes: * The overall duration for implementation includes standard times for development and consultation of Procedures and high-level implementation design with industry, technology delivery, and industry testing and trials. If tighter timeframes are required, the timeframes for each component of implementation (design, development and consultation of Procedures, technology delivery, market testing) would need to be compressed and follow a parallel path.*

Source: ESB analysis of EY and IES implementation cost reports.

The timeframes are indicative. The earliest operational date for the CRM is based on AEMO's current work program and prioritisation (which could be compressed depending on the urgency, needs and resources for competing priorities).

While the earliest estimated implementation date for the changed dispatch arrangements for priority access is January 2028, the associated rights could be allocated to market participants before the new systems are operational (for instance as part of a jurisdictional REZ scheme).

Given the long life of electricity assets, market participants can be expected to change their investment decision making process in anticipation of the new rules. An extended transition period can also help to smooth the impact of the reforms on market participants' contractual arrangements. As old contracts expire and new contracts are entered, market participants can update their arrangements in response to the new rules.

4 Context for the options

This chapter provides some additional context to the options. While the options were designed given the specific context of the NEM, they have fundamental features which are common, long-standing and widely regarded as best-practice internationally. There are also important similarities – and differences – between the two operational timeframes models.

4.1 International precedent

While the specifics of the CRM or CMM have never been implemented internationally in the form proposed, at their heart they both involve a price signal that varies by location on the transmission network. For instance, by purchasing congestion relief, a market participant is effectively buying the ability to optimise their output in the face of network congestion.

Many markets around the world have implemented a market design that incorporates locational marginal prices (LMPs) often in combination with financial transmission rights (FTRs). Such models are common and long-standing – having been progressively implemented in all eight US markets between 1998 and 2014, New Zealand in 1996 and elsewhere.[9] Reforms of this nature are also being considered for implementation in the Great Britain market and Ontario.[10]

The term "LMP" has come to be associated with a particular style of market that many generator and investor representatives strongly oppose. Consequently, the ESB has worked closely with stakeholders to develop an alternative approach to congestion management that avoids the features that stakeholders find problematic. The proposed approach dynamically allocates access in each dispatch interval based on bidding as occurs today. The CRM market then provides opportunities to trade and deliver efficiencies. Importantly, the CRM is designed to enable market participants to manage any adverse interactions with the contract market by making the CRM opt-in and giving market participants the ability to trade in congestion relief separately to energy.

While there are important differences between the models under consideration by the ESB and those implemented elsewhere, these models share the key feature that unlocks the efficiency savings in operational timeframes – namely, congestion is priced at localised points on the network. The congestion relief market uses local prices because congestion is local. For example, congestion in South-West NSW can only be relieved by generators/storage in that locality. It would be futile to pay the same price to generators in Northern NSW, because they cannot help to relieve that congestion. Consequently, local congestion relief prices are required.[11]

The CRM results in a well-functioning market because it uses a pricing mechanism to allocate a limited resource – access to the transmission network – to parties that value the access the most (taking into account their contractual positions). Even though it uses a very different approach, the ESB considers that the CRM achieves operational efficiency savings comparable to those associated with traditional LMP markets in other jurisdictions.

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9 Other examples are Mexico and Chile.

10 See: https://www.ofgem.gov.uk/publications/locational-pricing-assessment and https://www.ieso.ca/en/Market-Renewal

11 Given this shared characteristic, the ESB's Directions Paper used the term "LMPs" to describe the local congestion relief prices within the CRM. However, given its unhelpful connotations, we have adopted the more familiar language of "CRM price" in subsequent documents.

4.2 Similarities and differences between CRM and CMM

Many fundamental features of the CRM and CMM are the same. The main difference between the CRM and CMM are the way in which they distribute wealth between market participants, and that the CRM is voluntary.

4.2.1 Promote operational efficiency in a similar way

In the CRM, market participants are initially chosen for dispatch (or not) based on the existing energy market design. They then trade the right to increase or decrease their dispatch target at a price determined in the second market.

In the CMM, market participants compete to be dispatched at a price determined in the one single market, with participants whose output results in others being curtailed having to pay a charge. Regardless of whether they are actually dispatched, they are then rebated some of the revenues received via the congestion charges.

In terms of the underlying mechanism, the operational efficiencies of the CRM and CMM are expected to be the same: the same overall combination of generators being dispatched, and the same cost savings compared to the status quo. However, there are important differences in the way the options are implemented which affect the costs and benefits – and the winners and losers.

4.2.2 Different winners and losers

In the CRM, the revenue from the sale of energy at the RRP goes to the market participants that were dispatched in the initial energy market. Given that it is based on the rules of the existing energy market, this can be expected to be the market participants that are currently dispatched during periods of congestion.

Furthermore, the CRM is voluntary. Generators that currently dispatched can expect to continue to receive an initial dispatch allocation once the CRM has been introduced. They can choose not to reduce their output (and make up for that reduced output by buying energy in the CRM), meaning that they are unlikely to be worse off than under the status quo. Similarly, generators that are currently constrained off can choose to sell more energy, which presumably they would only do if this made them better off. Again, these market participants are unlikely to be worse off than the status quo. Market participants can choose to avoid implementation costs associated with the reforms if they do not want to participate. For those generators that are substantially affected by congestion, it is likely to be in their interests to participate.

In contrast, in the CMM, the revenue is involuntarily allocated on the chosen algorithmic basis.

These differences are important to existing and forthcoming market participants as it will impact their profits and risks. The CRM, by making an initial allocation of value through the existing market, has the least effect on existing market participants and promotes all market participants being no worse off, whereas the CMM may involuntarily redistribute value compared to the status quo – with winners, losers, a different allocation of risk, and different implementation costs for market participants compared to the status quo. These differences mean that the CMM exposes at least some market participants to risks that do not arise under the CRM.

5 Benefits and costs of the options

This chapter sets out our quantitative assessment of the costs and benefits of the four options for reform. There are four main sets of benefits and costs which we assess in turn:

- **Operational efficiency benefits**. The reforms change the incentives on generators and their bids into the market that determine dispatch changes. As a result, the costs of dispatching the system and emissions are lower compared to status quo.
- **Capital expenditure efficiency benefits**. The policy reforms reduce the returns available to new generators in locations subject to transmission constraints relative to locations with high transmission hosting capacity. As generation investments are in better locations, less generation capacity is needed, and less transmission capacity is built to evacuate electricity from poorly located generation to meet the same demand for electricity and for the same amount of emissions.
- Initial and ongoing **costs for market participants**. These costs are investments in systems and to accommodate the new approach, and legal costs of changing contractual arrangements.
- Initial and ongoing **costs for AEMO**. This is mainly up-front costs of systems to manage new dispatch arrangements.

We also consider the impact of the reform on the cost of capital for generation investment and transfers between generators and consumers (wealth transfers).

5.1 Modelling the benefits of reforms

The ESB has commissioned NERA to undertake market modelling of the CRM and CMM in operational timeframes.[12] NERA undertook a similar modelling exercise in 2020 for the Australian Energy Market Commission.[13] The 2020 modelling also undertook an analysis of the capital expenditure inefficiencies under the status quo arrangements. While the 2020 modelling for both capital and operational efficiencies did not specifically consider the four options that are the subject of this cost benefit analysis, it estimated the size of the benefits that the current options are seeking to capture, and so has significant relevance for this cost benefit analysis.

Quantifying the benefits and costs of any reform involves considering the *changes* in the benefits and costs versus the status quo arrangements. In our case this includes determining the total electricity system costs (i.e. the sum of all the costs of using fuel to generate electricity and capital expenditure over time) under the status quo arrangements, and again under the reform options, with the benefits (or costs) being the difference between these numbers.

Estimating the total electricity system costs – operational and capital – under each reform option is *relatively* easy. By removing the externality, the total electricity system costs are expected to be the same as the lowest possible total electricity system cost to meet demand. This in turn makes modelling the total costs as a result of the reforms *relatively* simple, given the costs of each of the resources in the system.

12 NERA (2023), Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM.

13 NERA (2020), Cost Benefit Analysis of Access Reform: Modelling Report Prepared for the Australia Energy Market Commission. 7th September 2020.

In contrast, modelling operating and capital costs in the status quo has proved to be extremely challenging because it is difficult to model the complex, perverse incentives that arise under status quo arrangements. NERA's latest report outlines numerous ways in which the results should be interpreted with care. Similar historic modelling (e.g. NERA in 2020) also proved difficult.

On the one hand, this is a limitation of this cost benefit analysis: if the benefits of the reform are uncertain, then whether they outweigh the costs is uncertain. But on the other hand, the uncertainty surrounding the benefits arise precisely because of the complicated, perverse and non-market-based outcomes in the status quo.

We have also identified various international studies into market models that price congestion (e.g. locational marginal pricing or more granular regional pricing). Clearly, each of these studies has limitations. Some are quite old, and each assesses systems which have different pre-reform transmission access arrangements than the current NEM (which, to our knowledge, has unique arrangements). These systems also have different network topologies, generation mixes, load profiles etc at the time of the study and over the study horizon, all of which influence the benefits of the reforms.

5.2 Estimating the operational benefits

As noted in section 3.3, the operational benefits arising from the CRM and the CMM are expected to be the same in any given year once the reforms are embedded. Acting rationally, market participants will bid in the CRM and the CMM in such a way that the physical outcomes are expected to be the same. Section 2 also notes that there are not expected to be any operational benefits (or disbenefits) from the priority access model or congestion fee (assuming the former is combined with the CRM/CMM). The following discussion therefore applies to both the CRM and CMM and to neither of the congestion fee or priority access models.

5.2.1 NERA modelling (2023)

We have two main sources of information for the quantitative benefits of the reforms in operational timeframes.

NERA has undertaken a recent, NEM-specific study which includes analysis of the operational benefits arising from introducing either the CRM or CMM.[14] This study involved considering two specific years (2023/4 and 2033/4). Its key findings about efficiency gains are replicated below:

Table 5: Fuel Costs ($m, 2023-24 and 2033-34, $2023)

Model Run	Generation Cost 2023-24	Generation Cost 2033-34
Base case	2,881	2,176
CMM or CRM	2,841	1,561
Difference	40	615
Percentage difference – base case vs reform	1.4%	28.3%

Source: NERA analysis of PLEXOS outputs.

A breakdown of the generation source in the base case and CMM / CRM runs for both years is provided in the table below.

14 NERA (2023).

Table 6: Generation by source base case vs CRM and CMM

GWh	2023/4			2033/4		
	Base case	CRM or CMM	Difference	Base case	CRM or CMM	Difference
Coal	118,769	117,388	-1,381	16,925	18,890	1,965
Gas	1,459	1,406	-53	17,306	12,611	-4,695
Liquid fuel	28	47	19	212	134	-78
Renewables	71,707	73,094	1,387	172,582	177,095	4,513
Total	**191,963**	**191,935**	**-28**	**207,025**	**208,730**	**1,705**

Source: NERA analysis.

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. The difference of 28 GWh in 2023/4 is a very small proportion of total generation/demand.

As can be seen from the table, in 2023/4, the main effect is a substitution of coal for renewables as we move between the status quo arrangements to the CRM or CMM. The substitution away from coal is material and in a single year is almost the equivalent of shutting one of Liddell's four coal reactors.[15]

In 2033/4, there is a significant amount of lost load reported in the base case (i.e. less load being met than under the CRM or CMM), arising from difficulties in the modelling process (discussed on page 26 of the NERA report). Setting this methodological issue aside, we primarily see a substitution from gas to renewables in 2033/4 under the reform option compared to the current arrangements (modelling also suggests a smaller increase in coal generation). Given the size of the shift away from gas and noting that gas is more expensive than renewables (and coal), the total benefits are estimated to be much larger in 2033/4 compared to 2023/4.

5.2.2 Historic and international studies

Various historic international studies relating to the operational benefits arising from the introduction of LMPs have been conducted internationally and with specific regard to the NEM, to investigate implementing the reforms in those jurisdictions, or as an ex-post analysis where locational marginal pricing has been introduced. As noted in section 3.3, the CRM and CMM both derive their benefits from implementing localised congestion pricing, and so these international studies provide useful ballpark figures for this cost benefit analysis.

We have identified thirteen data sources looking at operational efficiencies gained from more efficient dispatch. Six of these studies were considered by NERA in their March 2020 report.[16]

15 Liddell reactor 4 generated 1.9 TWh in 2022.

16 NERA (2020a), Costs and Benefits of Access Reform: prepared for the Australian Energy Market Commission, 9 March 2020. Page 27.

Table 7: Summary of operational benefits

Market or jurisdiction	Year of study	Source	Cost savings as a percent of fuel costs	Annual cost savings in the year of the study
Australian NEM	2026	NERA (2020)	6.50%	160m AUD
ERCOT (USA)	2020	Triolo & Wolak (2020)	3.90%	N/A
Western Europe	2016	Aravena & Papavasiliou (2016)	2.80%	N/A
European Union	2013	Neuhoff et al. (2013)	2.65%	1,400m EUR
MISO (USA)	2007	Brattle (2009)	2.61%	172m USD
CAISO (USA)	2009	Wolak (2011)	2.10%	105m USD
SPP (USA)	2005	CRA (2005)	2.00%	N/A
Australian NEM	2023/24	NERA (2023)	1.40%	40m AUD
ERCOT (USA)	2004	ERCOT, TCA and KEMA (2004)	1.05%	76.3m USD
ERCOT (USA)	2008	CRA and Resero Consulting (2008)	0.60%	73.6m USD
European Union	2011	Van der Weijde & Hobbs (2011)	0.50%	N/A
European Union	2009	Barth et al. (2009)	0.10%	N/A
IESO (Ontario)	2017	Brattle (2017)	N/A	84m CAD
Great Britain	2030-50	Aurora (2020)	N/A	1,900m GBP

Source: ESB analysis of various sources.

A similar range of operational benefits of 0.1% to 3.5% is found in literature discussed by Simshauser et al. (2021).[17]

Using the figures provided in each of these studies has limitations, as noted in section 5.1 above. Reforming arrangements in one jurisdiction may have different impacts than reform in the NEM. While the key benefit of reform in the NEM and in other jurisdictions is the same, namely the dispatch of cheaper generation, the generation technologies which get substituted are likely to vary. For example, the shift might be from gas to coal or from gas to solar, resulting in different cost savings. Furthermore, the likelihood of a substitution depends on how congested the network is. The more congested the network the more substitution will occur and the greater the cost savings. This again means that the cost savings will not be the same. We are unable to adjust these studies to take either of these differences into account.

That said, while each individual study may be discounted as not reflecting the benefits of the CMM or CRM, collectively they demonstrate that the operational cost savings provided by NERA[18] for 2023/24 of 1.4% are within the range observed elsewhere.

17 Simshauser, P., Billimoria, F., & Rogers, C. (2021). Optimising VRE plant capacity in Renewable Energy Zones. University of Cambridge, Faculty of Economics, p. 8. This study notes the possible high transaction costs from moving to an LMP market. The specific designs of the CRM and CMM seek to reduce these transaction costs compared to a "standard" LMP model applied internationally. Notably, under the CRM, contract reopening may not be required because the CRM is voluntary.

18 NERA (2023) Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM – prepared for the Energy Security Board. See also the ESB companion document, Transmission access reform Modelling the congestion relief market, February 2023.

5.2.3 Determining future benefits

One of the key challenges in estimating the benefits of the options is that the likely annual benefits may change substantially over time. Simply applying the percentage savings to the projected operational costs savings from the above studies – for example using the ISP's forecasts – could substantially misestimate the potential benefits of the options.

While the operational costs for the NEM are projected to decline substantially as the generation mix becomes increasingly dominated by near zero-cost variable renewable generators and storage, there is good reason to think that the percentage and dollar savings are themselves a function of the generation mix. As the generation mix changes over the period of investigation, so too might the percentage savings, meaning that applying a fixed percentage saving may be inappropriate.

This effect is illustrated by NERA's estimate of the benefits for 2033/4. Given the uncertainty associated with the energy transition, and the challenges of modelling the distortions that arise under the current market design, we have not relied on the NERA's 2033/4 modelling results as part of the cost benefit analysis. However, several illuminating trends can be drawn from the modelling exercise.

While the total operational costs of running the system is expected to decline compared to 2023/4 as more renewables enter the system as projected by the ISP, the benefits of the reforms increase in absolute terms. The percentage benefit increases significantly.[19]

As discussed in section 5.2.1, a benefit of the reforms is the substitution of relatively high-cost generation (and low value load) with relatively low-cost generation (and high value load), as well as the more efficient use of storage to enable an increase in relatively low-cost generation. The size of the benefits is a function of which generators (and storage) are substitutes for which, as well as how often this happens. NERA's results show that in 2023/4, the majority of the savings come from a substitution from moderately high-cost coal to low-cost renewables (see Table 6 above).

By 2033/4, the generation mix assumed in NERA's study (from the 2022 ISP) has substantially less coal, far more renewables, and much gas capacity remaining in the system. In an efficiency system, this gas capacity is required to meet occasional peaks in demand or shortfalls in renewable energy supply, and so would only be rarely used. But under the status quo arrangements, this gas is forecast to be more frequently and unnecessarily used, offsetting renewables which are "spilt". Consequently, the substitution in 2033/4 is forecast to be renewables (and to a lesser extent coal) replacing gas.

Furthermore, as storage plays an increasing role in the generation mix, the operational inefficiencies incentivised by the current arrangements for storage are likely to also increase. Under the current arrangements, storage fails to complement renewables when congestion is present if it acts as generation rather than charging to enable more renewables dispatch.

Countervailing these effects is the possibility that as the generation mix becomes more uniform in its costs, the cost of substituting between generators will be lower.

To summarise the benefits of the CRM and CMM are a function of the specific generation mix and network topology. While the international studies indicate that NERA's 2023/4 study is credible, they do not provide particular indication as to the likely benefits going forwards for the NEM, given the radical change in generation mix.

19 NERA (2023) Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM – prepared for the Energy Security Board. See also the ESB companion document, Transmission access reform Modelling the congestion relief market, February 2023.

5.2.4 Impact of opt-in on benefits under the CRM

A key feature of the CRM is that it is opt-in: market participants choose whether to participate. This is a critical difference between the CRM and CMM.

Under the CRM, market participants may decline to participate in the CRM and instead retain their initial allocation, even if there is scope to profit through trading. We consider that this effect would be short lived as generators would choose to participate rather than leave “money on the table”. However, the opt-in feature helps to manage the transition risks associated with the CRM.

A key reason why generators may decide against participating in the CRM is their contractual arrangements, particularly if they have contracts that relate payment to physical dispatch. In the short term, non-participation may be indicative of high transitional costs associated with the need to renegotiate existing contracts. As these contracts roll off, the need to renegotiate ceases. When entering into new contracts, it would be in the interests of the contracting parties to enter into arrangement that enable market participants to take advantage of the opportunities for additional profit afforded by the CRM.

If we were to adopt a mandatory approach – i.e. the CMM – it is reasonable to anticipate that these transitional issues would lead us to defer the implementation the CMM in order to give market participants time to update their contracts. As a result, the potential benefits of the CMM would be deferred. Given the duration of the current portfolio of PPAs including some older long-term PPAs, we would expect the deferral to be around four years, to 2030. The opt-in nature of the CRM makes it possible to introduce the reforms more quickly and gives market participants an incentive to minimise the transitional costs.

In the long term, if generators still don’t participate in the CRM, the benefits of the CRM will reduce, although we consider this unlikely given it is in their interests to participate. Market participant costs will also fall, however AEMO’s implementation costs would be the same.

5.2.5 Summary of results and discussion

The following table provide estimations of the operational benefits of the reforms (excluding costs).

The CRM and CMM retain these estimated values of operational benefits when combined with the congestion fee or priority access.

Table 8: Policy options and operational benefits NPV (2023-2050) ($AUDm 2022)

Policy option	Low benefit	High benefit
CRM	$334m	$639m
CMM	$289m	$552m

Source: ESB analysis of NERA (2023) and NERA (2020).

These estimations necessarily require a degree of judgement. Our rationale is provided below.

CRM

Low benefit

As a conservative low estimate, the dollar value of the benefits determined by NERA (2023) for 2023/4 with partial participation of generators (i.e. $31m AUD(2022)) is assumed in 2028, rising linearly to the estimated dollar value of the benefits determined by NERA (2023) for 2023/4 ($40m) with full participation by 2030, and holding at that level for the remainder of the study period to 2050.[20]

There are various factors which might indicate that this is a low estimate, discussed above:

- the likelihood, as indicated by the modelling for 2033/4, that the benefits rise in the future as more gas (rather than coal) substitutes renewables
- the substantial inefficiencies arising from batteries which can under the status quo arrangements be incentivised to discharge even when charging is efficient, and which will become an increasingly prominent part of the fuel mix
- the fact that 1.4% is towards the low end of the benefits found in international studies, particularly the more recent international studies
- the possibility that more generators opt into CRM trade than estimated.

Conversely, there are reasons that may put downward pressure on the benefits:

- the possibility that as the generation mix becomes more uniform in its costs, the cost of substituting between generators will be lower
- the possibility that fewer generators may participate in the CRM than estimated, which may be strongest shortly after the introduction of the reforms
- the fact that some international studies indicated lower benefits.

On balance, the reasons why the estimate is likely to be low strongly outweigh the reasons to think that the estimate is likely to be high.

High benefit

While the NERA (2023) modelling for 2033/4 indicates a benefit of $615m for that year, there are too many limitations in the modelling to justify including this figure in the high estimate. This number is inconsistent with the benefits modelled internationally, and is also an order of magnitude different to the 2023/4 modelling and the modelling of 2028 undertaken by NERA in 2020.[21]

Instead, as a high estimate, we have adopted Triolo and Wolak's (2020) estimate of the benefits of reform in Texas, a market that shares many similarities with the NEM. This is 3.90% per year or approximately $76 million a year.[22]

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20 NERA's partial participation scenario selects generators with the bottom 50% dividends and extends this selection to achieve 50% non-participation by variable renewable generators (most likely parties to PPAs). These generators are assumed to not participate in the CRM. Modelling assumes their dispatch level and market outcomes are unchanged from the energy market.

21 NERA (2020).

22 Calculated by multiplying 3.90% by total fuel and variable operations and maintenance (VOM) costs in 2028 from the 2022 ISP (Step-change scenario, candidate development path 12).

We have reduced this figure between 2028 and 2030 to account for partial participation, scaling linearly from $59m[23] in 2028 to $76m in 2030 and then holding at $76m for the remainder of the study.

This figure is plausible given that it is considerably below the modelled figure for 2033/4 and is consistent with the view that the benefits are likely to increase over time as the generation and storage mix of the sector changes. We consider this figure could be conservatively low.

CMM

Low benefit

As a conservative low estimate, the dollar value of the benefits determined by NERA (2023) 2023/4 (i.e. $40m) is assumed in 2030, and holding at that level for the remainder of the study period to 2050.[24] This is different to the CRM. In the CRM, the benefits are assumed to be lower than $40m between implementation in 2028 and 2030 owing partial participation in the early years after implementation. In the CMM, which is mandatory and so will require a later implementation date, the benefits commence in 2030.

As with the CRM, this could be a low estimate for the reasons provided above (other than the possibility that generators do not participate).

High benefit

The high estimated benefit of the CMM is $76m (discussed above) applied every year from 2030. Again, this differs from the CRM, which includes annual benefits of between $59m and $76m between 2028 and 2030.

5.2.6 Emissions

The substitutional effect described above impacts emissions.

In both 2023-4 and 2033-4 NERA's modelling indicates a substitution of thermal generation for renewables. In both years the reduction in emissions is approximately 1 million tonnes of CO_2. In 2023-24, this represents approximately 1% of total power sector emissions. Under the ISP, the capacity mix shifts away from fossil fuels over time so in 2033-34 the base level of emissions is much lower. This is why the percentage change in emissions between scenarios in 2033-34 is much larger at approximately 4%. 1 million tonnes of CO_2 represents approximately the annual savings if one of Gladstone's coal units stopped generating.

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23 $59m being $76m multiplied by the ratio of the partial participation benefits ($31m) and full participation benefits ($40m) in 2023/4 modelled by NERA.

24 NERA (2023) discusses its approach to the partial participation scenario (pp. 25-27). The scenario selects generators with the bottom 50% dividends and extends this selection to achieve 50% non-participation by variable renewable generators (most likely parties to PPAs). These generators are assumed to not participate in the CRM. Modelling assumes their dispatch level and market outcomes are unchanged from the energy market.

Table 9: Emissions reduction between status-quo and reforms (CRM or CMM) (2023-24 and 2033-34)

Year	Change in emissions (tonnes CO_2)	Percentage of status-quo emissions
2023-24	1.1m	0.97%
2033-34	1.0m	4.32%

Source: NERA (2023).

We observe that the NERA modelling provides an approximately constant CO_2 saving of 1 million tonnes a year.[25] We apply this as our emissions reduction estimate from 2030 to 2050 in both the CRM and CMM.

In the case of the CRM, prior to 2030 we apply the ratio of the benefits in the partial participation benefits ($31m) and full participation benefits ($40m) in 2023/4 modelled by NERA in 2026 to 1m to derive a reduction of 0.8m tonnes in 2028, to account for partial participation in the CRM. We then linearly scale this to 1m tonnes between 2028 and 2030.

In the case of the CMM, we assume 1m tonnes of reduced emissions starting from 2030, when the reform is introduced.

We have also indicatively estimated the dollar value of these emissions, using estimates of carbon prices from the International Energy Agency (IEA).[26] Interpolating from the IEA's estimate of carbon prices for advanced economies with net zero emissions pledges (US$135/tonne in 2030, US$175/tonne in 2040 and US$200/tonne in 2050) we estimate the dollar benefit of reduced emissions.

Table 10: Emissions reduction between status-quo and reforms (CRM or CMM) (2023-2050)

Operational option	Emissions reduction (2023 – 2050)	NPV ($)
CRM	23 million tonnes CO_2	$1.9b
CMM	21 million tonnes CO_2	$1.7b
Congestion fee	0	0
Priority access	0	0

Source: ESB analysis of NERA (2023).

5.3 Investment timescale benefits

None of the options have been specifically modelled for the NEM over investment timeframes. Instead, studies have been conducted on the benefits in investment timeframes of prices that reflect localised congestion in the NEM (by NERA in 2020) and New York (2011).[27] In these models, the externality in investment timeframes does not arise, and so these studies provide an indication of the possible benefits of addressing this externality in investment timeframes.

25 NERA (2023) Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM – prepared for the Energy Security Board. See also the ESB companion document, Transmission access reform Modelling the congestion relief market, February 2023.

26 International Energy Agency, World Energy Outlook, November 2022, p.465. Available at: https://iea.blob.core.windows.net/assets/830fe099-5530-48f2-a7c1-11f35d510983/WorldEnergyOutlook2022.pdf

27 NYISO (2011), 2010 ISO/RTO Metrics Report, p. 257.

5.3.1 *Historic and international studies*

NERA's March 2020 report, which considered international evidence of the size of the inefficiency arising in the status quo for the NEM, converted annual benefits from a New York study on capital cost savings and found annual benefits of $327 million to $690 million (in 2019 $AUD).[28] An NPV of these annual benefits to 2050 (in 2022 $AUD) is equal to approximately $3.7 billion to $7.9 billion in benefits.

The study from New York is an imperfect comparator for the impact of the investment timeframes models. The New York figure dates from 2011 and was conducted on a system which has:

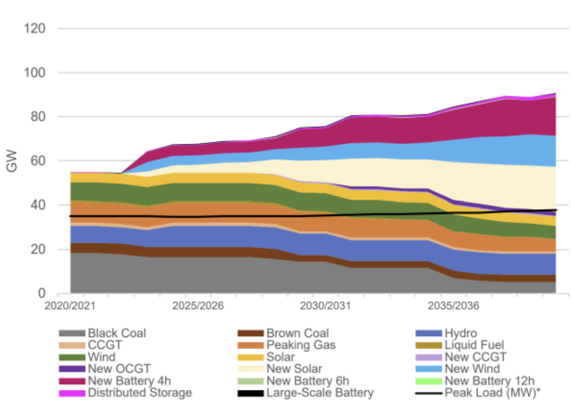
- different pre-reform transmission access arrangements than the current NEM
- different expected future network topologies, generation mixes, load profiles etc to the NEM.

Nevertheless, they are useful additional comparators which suggest that the NERA modelling of the size of the inefficiency in investment timeframes under the status quo is of a similar order of magnitude, and indeed may be conservative. NERA's September 2020 study which undertook NEM-specific modelling of the inefficiencies arising in investment timeframes in generation, storage and transmission in the NEM. These benefits include both changes in capital expenditure and the resulting changes in fuel costs arising from a change in generation stock. NERA provided a 15 years NPV from 2026 to 2040 of benefits of $1,700m (AUD2020).[29]

5.3.2 *Analysis of the inefficiency of the status quo arrangements*

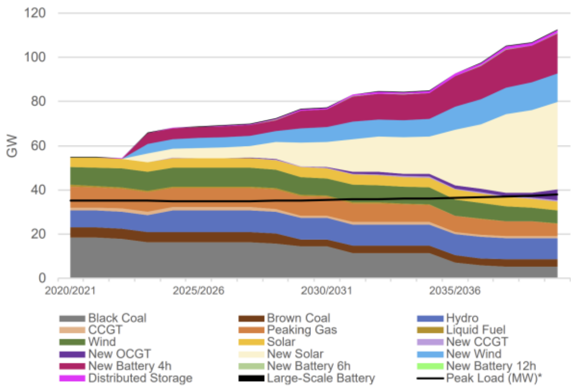
Given the limitations of the international studies, and to give a more conservative outcome, the rest of this quantitative analysis focuses on the NERA 2020 modelling. Figures 3.1 and 3.7 of that report, replicated below, demonstrated the projected profile of generator stock (as projected in 2020) under the reform and no-reform case (i.e. having internalised the externality versus not).

Figure 3.1: Capacity Mix for Reform Scenario 2020-2040 (GW)



Source: NERA Analysis

Figure 3.7: Modelled Capacity Mix in the No-Reform Case



Source: NERA Analysis of PLEXOS results

As can be see by comparing the graphs, the total generation capacity of the NEM is far higher without the reforms (approximately 110GW compared to approimately 90GW by 2040). This is consistent with the theoretical expectation that, under the base case, significant investment will cannibalise the generation of other generators, meaning that as the existing generation stock retires we must spend more capital on generation in order to deliver the same level of reliability or emissions reductions.

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28 NERA (2020a), Chapter 5.

29 NERA (2020), Chapter 3.

Alternatively, for a given level of capital expenditure we could reduce emissions by a greater extent under the reforms than under the status quo.

The capital cost savings are substantial. The largest solar farm currently connected to the NEM is Darlington Point solar farm with a rating of 275 MW.[30] The difference between the two scenarios is the equivalent of avoiding the installation of an additional 72 Darlington Point sized solar farms. Given that there are currently only 56 large scale solar farms connected to the NEM and all others smaller than Darlington Point demonstrates the scale of this difference.

Is transmission access reform a Solar Stopper?

Some stakeholders have characterised transmission access reform as Solar Stopper as they fear it will stop investment in renewables.

Transmission access reform supports efficient investment in renewables in line with government policy objectives and the Integrated System Plan. It does this, in part, by removing the opportunity for projects that are inefficient from a whole of system perspective to become privately profitable by cannibalising the output of others.

The reduction in renewable generation *capacity* does not result in a reduction in renewable generation *output* nor an increase in emissions. Rather, we build a smaller renewable generation fleet that is better utilised and we avoid building projects that cannot be used due to network congestion (or building otherwise unneccessary transmission to "save" poorly located projects).

The ESB notes that since the NERA report was prepared in 2020, the expected role for storage in the energy transition has substantially increased. As a result, the impact on storage investment decisions is likely to be understated.

Under the status quo arrangements, storage is not incentivised to locate efficiently, because of the implicit penality it receives when charging to alleviate congestion (that it, it should be paid for the benefits it provides to others, but is not). In turn, storage investors are less likely to invest behind constraints, even when efficient to do so, ultimately requiring more generation, transmission, or storage elsewhere than would otherwise be required. As thermal plant leaves the system more quickly than expected in 2020, the inefficiencies arising from misplaced and misutilised storage will be earlier, and so higher in net present value terms. Shafran and Day[31] examined trends in storage investment in the United State, with a focus on the differences between the markets that price congestion and those that do not. The US markets that price congestion are covered by independent system operators (ISOs) or regional transmission organizations (RTOs).

They found that storage was disproportionately located in ISO/RTO markets. Such markets accounted for 58% of grid capacity, but 74% of large-scale battery storage power capacity (GW) and 72% of energy capacity (GWh). They also found emerging evidence that storage in these markets was locating in the vicinity of renewable generation.

While congestion pricing is not the only relevant factor in driving the uptake of storage (for instance, the California ISO has a mandated storage target), the authors concluded that congestion pricing can play a helpful role.

Given the rapid change of the system, the correct incentives should be in place as soon as possible so that they can correctly incentivise the coming investment. Storage, in particular, can be deployed far more rapidly than transmission in order to faciliate the low-carbon transition of the sector. Upon

31 Shafran and Day (2022) Informing the REMA debate: International Learnings on Investment Support for Clean Electricity

implementing the reforms, the benefits of better placed storage is likely to start flowing quickly, alleviating constraints allowing more low cost, low emission generation to reach the marketplace, and further facilitating more investment in these technologies.

A possible example of capital investment inefficiency: Western New South Wales

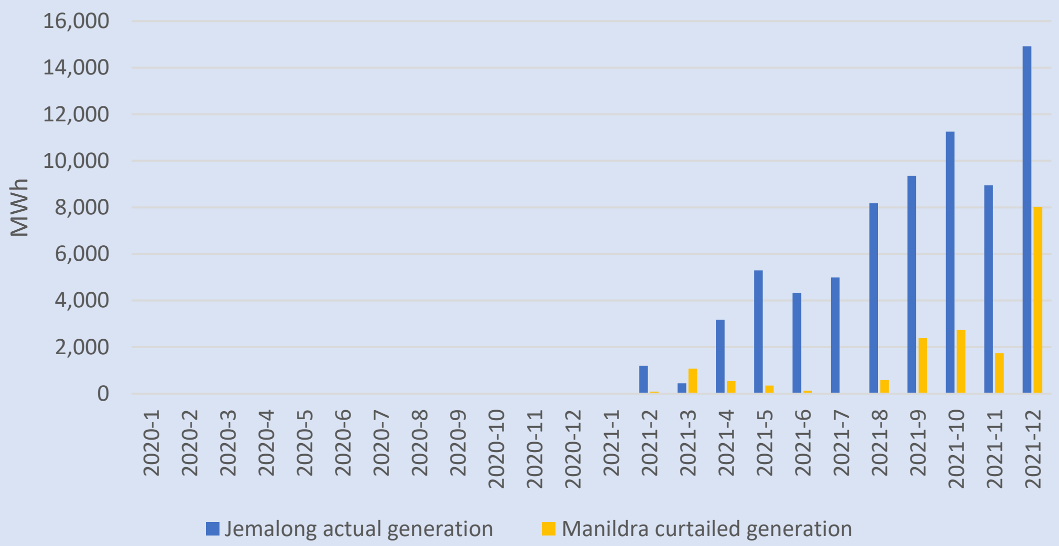
The inefficiencies discussed in section 2.3.2 and modelled by NERA (2020) appear to be happening in practice.

Manildra is a solar generator located near Orange in New South Wales. It has been operating since 2018. Prior to 2021, its output was unconstrained by tranmission capacity.

In early 2021 another solar generator, Jemalong, connected nearby. The output of this new generator, in combination with all the existing generators including Manildra, now sometimes exceed the capacity of a specific route across the network – between Molong and Orange North. Since early 2021, some generation in this location must be constrained off from time to time. A larger proportion of Malidra output flows across the congested part of the network than the other generators, including Jemalong, and so it is Manildra which is typically constrained off.

We have estimated the amount by which Malindra's was curtailed over this period, based on the output of nearby unconstrained solar generators as a proxy. The figure below shows that Malidra's estimated curtailment is strongly correlated with Jemalong's actual generation.

Manildra curtailed generation before and after connection of Jemalong



Source: ESB analysis.

It appears that Jemalong's generation is causing Manildra to be curtailed. The additional output of zero emission and zero cost generation as a result of Jemalong generating is less than than that of Jemalong's output. But Jemalong's investors are not incentivised to factor this into their investment decision because Jemalong is paid for its gross output, not the net output.

It is likely that an overall lower cost (and lower emission) combination of resources could have been employed by connecting a new generator elsewhere in the network instead of at Jemalong, allowing both its output and Malidra's output to reach the marketplace. This is not incentivised under the current arrangements.

5.3.3 Emissions

The Climate Change Act (Commonwealth, 2022) has implemented an emissions budget to 2030 and a 2050 target of zero greenhouse gas emissions. These budgets and targets – along with other regulations, legislation and government actions and investments – provide a framework which is intended to limit Australia's emissions.

In NERA's 2020 modelling, in both the base case and the reform case, emissions were unconstrained and differed to one another. The change in emissions policy impacts the likely inefficiencies in the status quo arrangements modelled by NERA (2020). The capital expenditure and fuel costs modelled in both the status quo and reform cases would be different to those modelled by NERA to constrain the emissions to targets. Given the new emissions policy, we expect that over investment timeframes the emissions under the status quo arrangements for transmission congestion will be the same as those arising from an efficient combination of resources as a result of the reforms, and in either case will match the legislated emissions targets and budgets.[32]

Reforms that successfully address the investment inefficiencies in the current arrangements will ensure that less resources (capital, labour etc) will be required to deliver the same emissions outcomes and meet the same demand, enabling a lower cost transition to a low-carbon economy. The benefits of the reforms would not be an emission reduction but a reduction in the cost of meeting the emissions targets.

5.3.4 Relative benefits of the options – incentivising efficient location decisions

The section above discussed the possible size of the inefficiencies under the status quo arrangements. What is relevant, for the purpose of a cost benefit analysis of the options, is the extent to which each option addresses the inefficiency. This in turn provides a measure of the benefit of option.

Qualitatively, we consider that both the congestion fee and the priority access options – which are intended to address these inefficiencies – could capture a large proportion of the benefits. Conversely, we consider that the other options in isolation (the CRM alone or the management model alone) are unlikely to capture a material share of the possible benefits in investment timescales.

Congestion fee

As noted in section 3.3, the congestion fee in theory directly internalises the externality. An accurately set fee (i.e. a fee which reflects the best-possible estimate of the future at the point in time that the fee was set), will internalise the existing externality, address the existing regulatory failure and so deliver the possible benefits in full.

In practice, determining the appropriate size of the congestion fee is challenging, given that it differs based on the level of either the rebate enjoyed by the market participant (CMM) or the value of the free access provided to market participants (CRM) over time. This is a complex function of the market participant's location, generation technology, the network topology and the presence of other market participants which also use the network near that location, both at the time the fee is set and into the future.

32 The only way this would not be the case is if the lowest cost way to meet demand for electricity resulted in lower emissions than the targets/budgets in one or other (or both) of the status quo and efficient cases.

That said, improvement merely requires a more accurate fee than the current arrangements, which implicitly sets a fee of zero. It seems reasonable that the organisation setting the fee will be able to achieve a considerably more accurate fee than the currently low bar. Given the potentially significant improvements on the status quo arrangements even if the fee is only modestly accurate, we expect this option could address a high proportion of the inefficiencies in the status quo.

Priority access

Similarly, we consider that the priority access model is also likely to internalise much of the externality. Depending on the exact design, in areas of the network which are already congested, a newly connecting market participant will bear a large proportion of the cost of the congestion it causes and will be unable to externalise it onto market participants already there who own priority access. The most significant examples of inefficient investment will therefore be addressed.

In areas of the network which are not congested, connecting generators do not impose negative externalities on other parties through their operation. The priority access model encourages market participants to take account of the externalities they impose on third parties by making priority access rights available in uncongested locations.

Congestion relief market

As the starting point for CRM trading is an initial dispatch round that is identical to the status quo, it does not address the externality in investment timeframes. However, it would improve signals for batteries or load to locate in areas which alleviate congestion as more CRM revenue would be available in these locations.

If a congestion fee or the priority access model were to be applied in combination with the CRM, any benefits from the CRM in investment timeframes might instead be addressed by the congestion fee or the priority access models. By assuming the benefits are zero in operational timeframes there is no possibility of double-counting the same benefit when the models are combined.

Congestion management model

The CMM is also unlikely, on its own, to fully address the regulatory failure in investment timeframes. The proportion of the costs that are internalised to the investor is a function of the rebate methodology, the network topology and nearby generators, but it is likely that only a small proportion of the costs are internalised. As with the CRM, the CMM could improve signals for batteries or load to locate in areas which alleviate congestion – in this case, via bigger diurnal spreads.

Again, benefits are more fully addressed if the CMM is implemented in combination with the priority access model or congestion fee. By assuming the benefits are zero in operational timeframes there is no possibility of double-counting the same benefit when the models are combined.

5.3.5 Summary of results and discussion

The following tables summarise our estimates of the investment related benefits of the reforms.

Table 11: Policy options and capital and fuel cost savings from more efficient locational decisions NPV (2023-50) ($AUDm 2022)

Policy option	Low benefit	High benefit
CRM	$0	$0
CMM	$0	$0
Congestion fee	$2,130m	$5,470m
CRM + Congestion fee	$2,130m	$5,470m
CMM + Congestion fee	$2,130m	$5,470m
CRM + Priority access	$2,130m	$5,470m
CMM + Priority access	$2,130m	$5,470m

Source: ESB analysis of NERA (2020).

As with the operational efficiency estimates, determining these numbers requires a degree of judgement, explained below.

Low benefit – congestion fee and priority access

The estimated low benefits of the congestion fee and priority access model have been directly derived from NERA's 2020 study (converted into 2022 AUD), which we consider to be most relevant given it is relatively recent study of the NEM itself.

For both the congestion fee and priority access model we estimate the benefits start to occur from 2026. In the case of the congestion fee, this is because it can be implemented in 2026 (even if implemented in combination with the CRM and the CMM, which would be subsequently implemented in 2028 or 2030, respectively). We expect that locational decisions of market participants will be improved ahead of the implementation of the priority access model (in 2028 in combination with CRM or 2030 in combination with CMM) providing priority access rights can be allocated ahead of when those rights become effective.

The following factors mean that the estimate is likely to be conservative given:

- the estimate is lower than that implied from the other international study identified
- capital expenditure is likely to be accelerated compared to expectations in 2020, including for batteries, increasing the benefits in NPV terms
- the estimate is limited to a 15-year period of annualised benefits (NERA's defined period in review ended 2040).

We have not identified any studies to provide evidence that the congestion fee would address more or less of the inefficiencies in the current arrangements than the priority access model – although the administrative challenges of calculating such fees are well known. This is not to suggest that the models are the same and so would deliver the same benefits, rather that we have been unable to identify a compelling case which suggests that one is clearly higher or lower than the other.

High benefit – congestion fee and priority access

The high estimated benefits of the congestion fee and priority access model have been directly derived from NERA's 2020 study (converted into 2022 AUD), but it extends the annual benefits to 2050.

The same benefits in 2040 are assumed to occur on an annual basis between 2041 and 2050 (the final years of our analysis). This is justified on the basis that benefits were likely to be both delayed and "cut off" in the low benefit estimate.

CRM and CMM

With regard to the CRM and CMM, we consider that the potential benefits and disbenefits of the models in investment timeframes are likely to be modest. For the purpose of this CBA they have been assumed to be zero. If the benefits of the CRM or CMM in investment timeframes are under-estimated, the benefits of the congestion fee or priority access model may be over-estimated by the same amount, because the congestion fee or priority access address the *outstanding* inefficiencies. Any inefficiencies addressed by the CRM or CMM cannot also be counted as a benefit for the congestion fee or priority access models.

5.4 Change in risk

5.4.1 How the reforms impact the cost of capital

CEPA was engaged to comment on the change to the cost of capital to generators due to the reforms.[33] CEPA indicated that the introduction of the CRM and priority access models could have a downwards impact on the factors that affect the cost of debt. The CRM increases generator profits (with none worse off). The priority access model provides protection against later cannibalisation by a new entrant.

The CMM could also lower the cost of debt for those generators whose profits would increase after the reform. However, some generators would experience a reduction in profits, pointing to a potentially higher cost of debt.

Relative to current arrangements, the congestion fee model could increase or decrease the cost of debt for new entrants, depending on the generator. For incumbent generators, congestion fees may reduce the risk of access being cannibalised by a new entrant, pointing to a lower cost of debt.

CEPA did not consider that the reforms are likely to have a material impact on cost of equity in either direction. CEPA considered a theoretical argument why these reforms may impact the returns demanded by equity investors, but concluded that in practice this effect may not be material, or indeed not present at all.

In combination, these conclusions point to an overall downwards impact on the risk factors that determine the cost of capital, for the CRM and priority access reforms. The effect is ambiguous for the CMM and congestion fee reforms.

5.4.2 How changes in the cost of capital affect the net benefits of the reforms

Standard cost benefit analysis of policy options focuses on the change in resource costs – capital and operational expenditure incurred – and not changes in financing costs. The rest of this cost benefit analysis follows this standard approach. To a first order approximation the standard approach would

33 CEPA, Transmission Access Reforms, Cost of Capital Impact, 2023.

always result in the same net benefit to society as a whole regardless of the change in risk for market participants resulting from a policy change.[34]

However, the policy intent of the reforms includes reducing risk for market participants. An indicative assessment of the cost of capital impacts is included for this purpose. A generator's profits include compensation for the risk it takes. If the risk goes down then the level of compensation required for that risk also goes down. Its "economic profit" (profit net of its cost of capital reflecting the risks) is unchanged as a result of the reforms. The investor is indifferent to the new (lower) level of profit given the new (lower) level of risk it takes. The impact is lower revenues and prices paid by consumers.

5.4.3 Estimating the impact of changes to the cost of capital

Estimating the extent to which a change in the cost of capital flows through to customers is a challenging exercise and is driven by assumptions. We have prepared a high level indication of the scale of the potential benefits to demonstrate that even a small change to the cost of capital can substantially reduce the revenues paid by consumers.

Our approach is to estimate a capital asset base for each year of the study, apply an estimated change to the cost of capital to the asset base in each year (the annual impact for consumers), and NPV the annual impact to determine an overall impact:

- We have estimated an opening asset base of approximately $14 billion for 2023. This is a conservative estimate based on approximate investment in generation of 12,500MW from 2018-21 and 1,500MW forecast for 2022.[35] Assuming a cost of approximately $1 million per MW,[36] gives an approximate asset base of $14 billion. This estimate is conservative as it assumes all investments made prior to 2018 are fully depreciated (i.e. do not form a part of the asset base). Conversely, it assumes no depreciation of assets between 2018 and 2022.
- In order to estimate the annual changes in asset base we assumed a 20-year straight-line deprecation schedule and used annual capex spending from the 2022 ISP[37] for new investment in generation.[38] The increase in the asset base between years is:
    - new capital expenditure forecast by the ISP in a given year, less
    - the depreciation of all historic expenditure within the base.
- Each year we multiply an estimate of the change in cost of capital by the total asset base, and then discount the annual results.

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34 To a first order approximation, there would be no further change in the capital and operational expenditure from a change to the cost of capital arising from the reforms. Subject to important caveats, the same demand would be met by the same combination of resources regardless of the cost of capital. There may be dynamic impacts which complicate the analysis. For example, if the cost of capital falls and this in turn leads to lower electricity prices there may be an increase in demand for electricity or secondary impacts in adjacent markets. Consumers will have more money to spend elsewhere and companies that use electricity may now be able to justify investments that were previously not possible. Conversely, investors that now do not receive this profit may well have to reduce their investments which will also impact the economy. Assuming the same physical resources employed to deliver the same outputs, under the standard approach there would be no benefits or costs to society as a whole from a reduction in the cost of capital. A reduction in the cost of capital would reduce prices, reducing expenditure by consumers and revenues for producers by an equal and opposite amount, netting to zero. The effect is counted as a benefit to consumers, but not to society.

35 AER (2022), State of the Energy Market 2022, September 2022, Page 50.

36 International Renewable Energy Agency (2021), Renewable power generation costs in 2021.

37 ISP Step-change scenario, candidate development path 12.

38 The ISP capex figure do not give an accurate number for investment in a particular year because investment costs are annuitised in the ISP and spread over the economic life of the asset. On average over 20 years they will provide a useable figure to estimate total asset base. See: AEMO (2021), ISP methodology, page 74.

We have not sought to quantitatively estimate the change in the cost of capital. Instead, the analysis above indicates that for each 0.1% change in the cost of capital, there is a decrease in revenues paid by consumers of approximately $408 million in NPV terms. Less conservative assumptions would result in lower costs to customers for a given change in the cost of capital.

The effect on the cost of capital of introducing the CMM or congestion fee is ambiguous. The effect of the CRM and priority access model appears more downward. The ESB's further stakeholder engagement as part of the detailed design process will help to clarify the likely magnitude of the effect.

5.5 Analysis of costs

5.5.1 AEMO implementation costs

The ESB has worked with AEMO and EY to prepare new estimates of AEMO's implementation and ongoing costs for the CRM, congestion fee and priority access model. This involved creating a system impact heatmap which determines which systems are likely to be impacted by each option. Given that further work is required to settle the detailed design of these options, these estimates are necessarily high level, with range of uncertainty of ± 50%.

While the estimates for AEMO's costs for the CRM are estimated to be higher than the CMM, the costs for the CRM have reduced significantly compared to the preliminary ESB estimates in the consultation paper.[39] The consultation paper's estimate of $300 million ± 30% was based on an assumption that the implementation of the CRM would trigger a need to replace the NEM's dispatch engine, with the result that the cost of CRM would commensurate with AEMO's previous estimate of the cost of introducing LMPs/FTRs as part of the Coordination of Generation and Transmission Investment (COGATI) review.

However, since May 2022, the CEC proposed (and the ESB adopted) an alternative CRM design that more closely leverages the existing market systems. As shown in the table below, this has reduced AEMO's implementation costs to only $62 million ± 50%.

Table 12: AEMO upfront and ongoing costs – CRM, congestions fees and priority access ($AUD 2022)

Policy option	Upfront cost	Annual cost	NPV midpoint (2023-50)
CRM	$16m-49m	$2m-6m	$62m
Congestion fee	$2m	$1m	$8m
CRM + Congestion fee	$19-52m	$3-7m	$70m
CRM + Priority access	$21-54m	$3-7m	$76m

Source: ESB analysis of EY data.

Estimates of AEMO's costs for the CMM were previously undertaken by the ESB as part of the Post 2025 Market Design review in 2021 and have been used in this cost benefit analysis.[40] Table 13 applies the CMM cost estimates from 2021, supplemented with the more recent estimates developed for priority access and congestion fees.

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39 ESB, Transmission Access Reform Consultation Paper, May 2022.

40 ESB, Post-2025 Market Design Final advice to Energy Ministers, Part C (Appendix), p.63: https://www.datocms-assets.com/32572/1629945838-post-2025-market-design-final-advice-to-energy-ministers-part-c.pdf

Table 13: AEMO upfront and ongoing costs – CMM based models ($AUD 2022)

Policy option	Upfront cost	Annual cost	NPV midpoint (2023-50)
CMM	$10-20m	-	$11m
CMM + Congestion fee	$13-24m	$1m	$19m
CMM + Priority access	$16-27m	$1m	$24m

Source: ESB analysis of EY data (congestion fees and priority access), ESB analysis (CMM).

5.5.2 Costs to market participants

In 2021, the AEMC undertook an assessment of the likely IT and legal costs of market participants transitioning to an LMP/FTR regime as part of the Coordination of Generation and Transmission Investment (COGATI) Review. As with our estimate of benefits, these historic estimates provide a reasonable starting point but have been adjusted to reflect the specifics of the policy options now being considered.

In the historic study, market participants were interviewed to gauge estimates. The participants were classified into five categories and grouped with other companies to gauge NEM wide costs by multiplying an estimate of the costs for each category by the number of participants expected in each category. The number of expected participants came from the AER[41] and AEMO.[42] The categories were as follows:

- large generator, including retail
- small generator, including retail
- stand-alone retailers
- market load
- transmission network service providers.

Broadly IT costs reflect the cost to set up and maintain IT services including software, testing, consulting etc. For instance, to participate in the CRM, market participants would need to upgrade their systems to enable them to submit CRM bids. To adjust these costs to reflect the specifics of the policy options now being considered, the costs of implementing the CRM were assumed to occur on a staged basis. Participation rates – and so costs – are assumed to rise between 2028 and 2030, consistent with the assumed proportion of benefits arising over time due to partial participation (see section 5.3.5). For CMM, IT costs are expected to relate to (among other things) changes to settlements, systems to forecast the impact of congestion charges and rebates, and updates to accounting systems and have been assumed to be the same as for the CRM.

In the historic study, legal costs are only incurred upfront and reflect costs to update contracts, renegotiation etc. The survey provided an average minimum cost across the NEM and an average maximum cost across the NEM which we have adopted as a lower and upper estimate of market participant costs in the CMM. Legal costs arising from implementing the CRM are expected to be lower than for the CMM. The CRM may avoid reopening contracts because it does not impact the operation of the existing energy market. Further, market participants may not participate in the CRM if they consider that their contracts will be reopened. We have used the low estimates of legal costs for the CRM.

41 AER (2021), "State of the Energy Market 2021", 30 June 2021.

42 AEMO – participant list.

The cost estimates between CRM and CRM were also adjusted to reflect differences in the timing of implementation of the two models. On balance, the CMM has higher estimated implementation and ongoing costs for market participants than the CRM.

The following tables summarise the NEM wide costs associated with the different policy options.

Table 14: Upfront legal costs to market participants (NPV $AUD 2022)

Policy option	Minimum cost	Maximum cost
CRM	$24m	$24m
CMM	$21m	$87m
Congestion fee	$0	$0
CRM + Congestion fee	$24m	$24m
CMM + Congestion fee	$21m	$87m
CRM + Priority access	$24m	$24m
CMM + Priority access	$21m	$87m

Source: ESB analysis of IES data.

Table 15: Upfront IT costs to market participants (NPV $AUD 2022)

Policy option	Minimum cost	Maximum cost
CRM	$37m	$105m
CMM	$33m	$93m
Congestion fee	$0	$0
CRM + Congestion fee	$37m	$105m
CMM + Congestion fee	$33m	$93m
CRM + Priority access	$37m	$105m
CMM + Priority access	$33m	$93m

Source: ESB analysis of IES data.

Table 16 Ongoing IT costs to market participants (NPV $AUD 2022)

Policy option	Minimum cost	Maximum cost
CRM	$59m	$118m
CMM	$51m	$101m
Congestion fee	$0	$0
CRM + Congestion fee	$59m	$118m
CMM + Congestion fee	$51m	$101m
CRM + Priority access	$59m	$118m
CMM + Priority access	$51m	$101m

Source: ESB analysis of IES data.

Table 17 Total costs to market participants (NPV $AUD 2022)

Policy option	Minimum cost	Maximum cost
CRM	$121m	$247m
CMM	$105m	$282m
Congestion fee	$0	$0
CRM + Congestion fee	$121m	$247m
CMM + Congestion fee	$105m	$282m
CRM + Priority access	$121m	$247m
CMM + Priority access	$105m	$282m

Source: ESB analysis of IES data.

Given that AEMO's estimated implementation costs for CRM are much lower than for COGATI (see below), the ESB's reliance on COGATI estimates for market participants' costs is potentially conservative.

5.6 Overall net benefits

The following table provides a summary of the benefits, net of the costs. In summary:

- **Operational benefits:** Both the CRM and CMM are estimated to give rise to similar efficiency savings in dispatch. These benefits are driven by the more efficient use of existing generation and transmission assets, such as a substitution from high-cost generation to low-cost generation during periods of congestion. Because the CRM is voluntary and so less disruptive to the contract market it can be implemented sooner with higher operational benefits: $335m-$639m compared to $289m-$552m for the CRM.
- **Emissions:** The low estimate noted above results in an estimated 23m tonnes of emissions savings by 2050 under the CRM, or 21m tonnes under the CMM. These figures are roughly equivalent to shutting a large coal-fired power station like Liddell entirely four years early, avoiding fuel costs and emissions but with no impact on reliability.
- **Investment timeframe benefits:** Savings in investment timeframes are significant. Modelling suggests that by 2050 under the congestion fee or priority access model we can have a system with 20 per cent less capacity but still delivering the same level of reliability and emission reductions because the average utilisation of generators improves, saving $2.1 to $5.5 billion in net present value terms to 2050.
- **Costs:** Estimated to be an order of magnitude less than the benefits when the investment and operational options are combined. The AEMO costs associated with the CRM are higher than the cost of the CMM when implemented alone or in combination with the investment timescale options. Market participant IT costs are similar between the options. The costs associated with contractual and market disruption are lower under the CRM than the CMM.
- **Market disruption impact.** The disruption associated with a redistribution of winners and losers between existing market participants may result in significant additional costs associated with the CMM.

In addition, the CRM and priority access model has potential to reduce the cost of capital for generators. The CMM and congestion fee models have more ambiguous impacts on risk.

Table 18: Summary of total benefits, mid-point NPV 2023 – 2050 ($AUD billions 2022)

	CRM alone	CMM alone	Congestion fee alone	CRM + congestion fee	CMM + congestion fee	CRM + priority access*	CMM + priority access*
Operational benefits	$0.49	$0.42	$0.00	$0.49	$0.42	$0.49	$0.42
Capital and fuel cost savings from more efficient locational decisions	$0.00	$0.00	$3.80	$3.80	$3.80	$3.80	$3.80
AEMO costs	$0.06	$0.01	$0.01	$0.07	$0.02	$0.08	$0.02
Participant costs	$0.18	$0.19	$0.00	$0.18	$0.19	$0.18	$0.19
Net benefits	**$0.24**	**$0.22**	**$3.79**	**$4.03**	**$4.01**	**$4.03**	**$4.00**
Net benefits exclude the following changes in market disruption and emissions.							
Market disruption; redistribution of wealth between existing generators	-	↑	-	-	↑	-	↑
Change in CO_2 emissions (tonnes)	-23m	-21m	-	-23m	-21m	-23m	-21m

** On a stand-alone basis the priority access model is unlikely to have the highest net benefit (and may have net costs) because it may not improve operational efficiency (and may decrease operational efficiency) for reasons outlined in section 3.4.2. For these reasons the costs and benefits of implementing it on a standalone basis have not been determined.*

Note: Rounding difference in table for CRM, CRM + congestion fee and CMM + priority access.

5.6.1 The preferred combination of options

The case for reform is clear, with estimated benefits for the hybrid options outweighing costs by an order of magnitude. The choice of hybrid option is less clear cut, with the low estimated net benefits of each being $2.1 billion, and the high estimates being $5.9 billion.

The preferred combination is the CRM and the priority access model.

Given that the CMM is mandatory, the ESB anticipates a need to defer the introduction of the CMM to give market participants time to update their contractual arrangements or to allow a sizeable proportion of existing contracts to expire, ultimately diminishing the benefits given the urgent need for these reforms. This need does not apply to the CRM as it gives market participants more flexibility as they adapt to the new regime, and an incentive to adapt as quickly as possible. As a result, the CRM delivers greater operational and emissions benefits and incurs lower legal implementation costs.

AEMO's estimated IT implementation costs of the CRM are greater than the CMM and are incurred sooner. While bigger than the costs of the CMM, the estimated costs of implementing the CRM are much lower than the ESB's earlier indicative estimates. The IT implementation costs to market participants are assumed to be similar for both models, but the legal costs lower for the CRM because it is voluntary.

Overall, the net benefits of the CRM are higher than that of the CMM: $335m-639m versus $289-552m. Further, important qualitative factors also play a critical role in our recommendations.

In comparison to the CMM, the CRM distributes benefits between generators in a manner which more closely reflects the status quo arrangements. As a result, the CRM better avoids "winners" and "losers" among market participants arising from the reforms. Rather than creating winners and losers, the voluntary nature of the CRM creates a framework whereby market participants can choose to earn additional profits by participating in the CRM. To encourage investment, it is a common principle in public policy that regulatory interventions do not substantially disrupt the allocation of value between existing market participants. This is better achieved by the CRM. The disruption associated with a redistribution of winners and losers between existing market participants – particularly when this is based on a regulatory decision rather than commercial factors – may result in significant additional costs associated with the CMM.

We have not identified any studies to demonstrate that the congestion fee would address more or less of the inefficiencies in the current arrangements than the priority access model – although the administrative challenges of calculating such fees are well known. As they are both targeted towards addressing the same regulatory failure, priority access and congestion fees deliver similar levels of efficiency benefits. There is no clear preference among stakeholders between the two models.

On balance, we prefer the priority access model for qualitative reasons. The administrative process to calculate congestion fees is inherently complex, and the priority access model addresses the risk that an efficient project is curtailed due to an inefficient subsequent connection that chooses to pay the fee. Consequently, priority access may have an advantage in terms of supporting and strengthening REZ schemes and is more likely to have a downward impact on cost of capital.

5.6.2 Other studies of the net benefits

Several other international studies have examined the benefits of improving the efficiency of price signals from implementing locational marginal pricing. These studies have a number of limitations for our purposes:

- pre-reform transmission access arrangements than the current NEM (which, to our knowledge, has unique arrangements)

- network topologies, generation mixes, load profiles etc at the time of the study and over the study horizon, all of which influence the benefits of the reforms
- the reforms being examined are not exactly the same as the options being considered in this CBA, i.e. they are for the introduction of locational marginal pricing, as opposed to the CRM, CMM, congestion fees or priority access model specifically.

Despite these limitations they do provide an overall estimate for benefits. We have converted the benefits to applicable to the NEM by converting the currencies and adjusting for the relative size of the markets.

Table 19: Other international studies

Study	Market	Timeframe	Benefits	Benefits (NEM)
FTI (2022)	Great Britain	PV to 2030	£30 billion	$36 billion
FTI (2022 for Ofgem)	Great Britain	PV 2025-40	£31 billion	$37 billion
Aurora (2020)	Great Britain	2030-50	£2.1 billion per year	$3.06 billion per year

Source: ESB analysis of FTI Consulting GB Locational Pricing – A framework for analysis of benefits and some initial results, 6 May 2022, and FTI Consulting | Ofgem: Updated modelling results, 20 October 2022.

These studies indicate that the benefits to the NEM as estimated above may be conservative.

5.7 Sensitivities of net benefits

We have undertaken sensitivity of the net benefits, outline below.

5.7.1 Varying discount rate

Consistent with CBA guidelines, we have estimated the benefits based on a discount rate of 4 per cent and 10 per cent (as opposed to the standard 7 per cent discount rate used throughout the rest of the report). Decreasing the discount rate will increase the net benefits, whilst increasing the discount rate will decrease net benefits. Regardless of the discount rate, the preferred case (CRM and priority access) remains the same, and the net benefits are positive.

Table 20: Summary of benefits ($AUD 2022) – discount rate 4%

	CRM alone			CMM alone			Congestion fee alone			CRM + congestion fee			CMM + congestion fee			CRM + priority access*			CMM + priority access*		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Operational benefits	$0.50	$0.72	$0.95	$0.44	$0.65	$0.85	$0.00	$0.00	$0.00	$0.50	$0.72	$0.95	$0.44	$0.65	$0.85	$0.50	$0.72	$0.95	$0.44	$0.65	$0.85
Capital and fuel cost savings from more efficient locational decisions	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3.16	$6.28	$9.41	$3.16	$6.28	$9.41	$3.16	$6.28	$9.41	$3.16	$6.28	$9.41	$3.16	$6.28	$9.41
AEMO costs	$0.12	$0.08	$0.04	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.13	$0.09	$0.05	$0.03	$0.02	$0.02	$0.14	$0.10	$0.06	$0.03	$0.03	$0.03
Participant costs	$0.32	$0.24	$0.16	$0.37	$0.26	$0.14	$0.00	$0.00	$0.00	$0.32	$0.24	$0.16	$0.37	$0.26	$0.14	$0.32	$0.24	$0.16	$0.37	$0.26	$0.14
Net benefits	**$0.05**	**$0.40**	**$0.75**	**$0.06**	**$0.38**	**$0.70**	**$3.15**	**$6.27**	**$9.40**	**$3.20**	**$6.68**	**$10.15**	**$3.20**	**$6.65**	**$10.10**	**$3.19**	**$6.67**	**$10.14**	**$3.20**	**$6.64**	**$10.09**
Net benefits exclude the following changes in market disruption and emissions.																					
Market disruption; redistributing wealth between existing generators	-			↑			-			-			↑			-			↑		
Change in CO_2 emissions (tonnes)	-23m			-21m			-			-23m			-21m			-23m			-21m		

** On a stand-alone basis the priority access model is unlikely to have the highest net benefit (and may have net costs) because it may not improve operational efficiency (and may decrease operational efficiency) for reasons outlined in section 3.4.2. For these reasons the costs and benefits of implementing it on a standalone basis have not been determined.*

Table 21: Summary of benefits ($AUD 2022) – discount rate 10%

	CRM alone			CMM alone			Congestion fee alone			CRM + congestion fee			CMM + congestion fee			CRM + priority access*			CMM + priority access*		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Operational benefits	$0.23	$0.34	$0.45	$0.20	$0.28	$0.37	$0.00	$0.00	$0.00	$0.23	$0.34	$0.45	$0.20	$0.28	$0.37	$0.23	$0.34	$0.45	$0.20	$0.28	$0.37
Capital and fuel cost savings from more efficient locational decisions	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.47	$2.38	$3.29	$1.47	$2.38	$3.29	$1.47	$2.38	$3.29	$1.47	$2.38	$3.29	$1.47	$2.38	$3.29
AEMO costs	$0.07	$0.05	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.08	$0.05	$0.03	$0.02	$0.02	$0.01	$0.08	$0.06	$0.04	$0.02	$0.02	$0.02
Participant costs	$0.20	$0.15	$0.10	$0.22	$0.15	$0.08	$0.00	$0.00	$0.00	$0.20	$0.15	$0.10	$0.22	$0.15	$0.08	$0.20	$0.15	$0.10	$0.22	$0.15	$0.08
Net benefits	**- $0.04**	**$0.15**	**$0.33**	**- $0.04**	**$0.12**	**$0.29**	**$1.46**	**$2.38**	**$3.29**	**$1.43**	**$2.52**	**$3.62**	**$1.42**	**$2.50**	**$3.57**	**$1.42**	**$2.52**	**$3.61**	**$1.42**	**$2.49**	**$3.57**
Net benefits exclude the following changes in market disruption and emissions.																					
Market disruption; redistributing wealth between existing generators	-			↑			-			-			↑			-			↑		
Change in CO_2 emissions (tonnes)	-23m			-21m			-			-23m			-21m			-23m			-21m		

** On a stand-alone basis the priority access model is unlikely to have the highest net benefit (and may have net costs) because it may not improve operational efficiency (and may decrease operational efficiency) for reasons outlined in section 3.4.2. For these reasons the costs and benefits of implementing it on a standalone basis have not been determined.*

5.8 Assumptions and inputs to cost benefit analysis

We have made several assumptions in order to quantify and model net benefits of the various reforms. We made the following assumptions:

- We assumed a discount rate of 7% when estimating the present value of future cash flows. This is consistent with Australian CBA guidelines. We have also estimated net benefits assuming a discount rate of 4% and 10% (section 4.10.1).
- All prices are set to September 2022, reflecting best available inflation data for Australia and the United States.
- The length of our NPV is 20 years of benefits (NPV of 2023 – 2050), assuming 3 years where there are no benefits until the reforms are implemented.

PART B – Enhanced information

1 The policy problem

Market participants need good information to make informed production, consumption, investment, disinvestment and contracting decisions. Insufficient or misleading information is a source of market failure prompting inefficient outcomes. Information that is hard to find or verify may also create costs for market participants.

The ESB and stakeholders have identified possible deficiencies in the information available to market participants relating to the transmission network, which may be prompting inefficient decisions. In general, the deficiencies relate to insufficient or inaccurate information on under-utilised network capacity across the network, and how this depends on:

- diverse real-time conditions (demand, generation output (both of which depend on diverse factors such as weather conditions) and transmission and generation outages).
- future investments (and disinvestments) in network capacity, generation, storage and load.

There are also deficiencies in the way information is currently organised and published across multiple resources and by multiple authors e.g. AEMO and multiple transmission network service providers.

2 The policy options

At this stage, the ESB has considered the possible costs and benefits of a single high-level option to address information deficiencies in the status quo. This option might involve:

- providing investors with an initial screening of the level of congestion in different areas of the network:
    - indicative hosting capacity values
    - making underlying data accessible for investors to conduct their own project-specific market modelling and power system modelling
    - curtailment forecasts.
- information on future network augmentations and new connections (including generation and storage)
- a centralised portal based on existing interactive mapping tool.

Over the coming months the ESB intends to more closely examine the relative costs and benefits of specific alternative sub-options to improve information deficiencies. These options may also include those that change the information provided by transmission network service providers (TNSPs).

The relative costs and benefits of the option versus the status quo are discussed below.

3 Costs, benefits and implementation timeframes

Costs

A high-level estimate of the costs to AEMO of the option described above has been estimated to be approximately:

- capital costs of $4.3m
- annual costs of $0.6m.

The resulting NPV is $9.3m.[43]

Different costs may be incurred depending on the specific design of the option. Costs may also be incurred by other parties, such as TNSPs.

Benefits

The benefits of improved information relating to congestion could be significant. The ISP is forecasting $76 billion in generator capital expenditure and a further $11 billion in REZ and flow path augmentation to 2050 in NPV terms: five orders of magnitude higher than estimated costs.[44] Even if only one poorly located utility-scale project was abandoned due to the enhanced information, the reform would be justified. Capital efficiencies in the order of just one hundredth of one per cent would approximately equal the implementation and ongoing costs of the option to improve information.

The ESB has not established a quantitative estimate of the benefits of the option. In part this is because detailed option design will be undertaken in the coming months. The ESB also notes it is inherently difficult to establish quantitative estimates of the inefficiencies arising from poor information, nor the improvements that might arise from better information. Given these difficulties, the AEMC's analysis of the benefits of better information when making rule changes is typically qualitative.[45]

Implementation timeframes

Enhanced information has been assessed as a 'medium' complexity and has an estimated delivery timeframe of 19 months. The same assumption about simultaneous implementation can be made. This is on the basis that there will be the need for a new infrastructure build to enable appropriate data sourcing for collation of information provided. The engagement and consultation with industry to develop a consistent methodology for providing information is assumed to have high impact.

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43 Discounted at 7% over 20 years, consistent with the discount rate and timeframe applied throughout this report.

44 AEMO ISP, step change scenario, candidate development path 12, discounted at 5.5%.

45 For example see the following AEMC rule change determinations: *Enhancing information on generator availability in MT PASA* rule change (2022); *Transparency of new projects* rule change (2019); *AEMO access to demand forecasting information* rule change (2015).

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