FAQs | Directions Paper | Transmission Access Reform

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1. General	Is transmission access reform required given the pipeline of transmission investment projects and announced funding commitments including Rewiring the Nation?	Transmission congestion will increase, even as we build new transmission. AEMO's Integrated System Plan (ISP) forecasts the ideal level of curtailment if we deliver a least cost transition that follows the optimal development path. Congestion is a normal, everyday feature of efficiently sized transmission infrastructure to accommodate variable renewable generation – not an anomaly. Globally, power systems are experiencing an increase in congestion costs in line with an increase invariable renewable generation. Congestion is likely to increase because the cost of building the incremental transmission infrastructure needed to allow the dispatch of variable renewable generation at the sunniest or windiest of times exceeds the benefits of reducing the cost of dispatch or reducing emissions at those times from the dispatch of VRE. Even with an efficiently designed system, the volume of unused VRE in the NEM increases 16-fold between 2025 and 2050, from 5 to 80 terawatt hours (during this time forecast utility-scale VRE capacity also increases from 24 gigawatts to 140 gigawatts).[1] In the absence of reform, actual levels of curtailment are likely to exceed the levels forecast in the ISP. The ISP models the suite of transmission and supply-side projects that together deliver the optimal development path, but there is no requirement for generators to locate in accordance with the ISP. The scale and cost to consumers of the optimal development path is already significant. To protect consumer and taxpayers' interests – and facilitate the transition to greater reliance on renewable energy generation – it is vital to ensure that all our existing and new infrastructure is used as efficiently as possible, benefitting consumers.
2. General	Do we need a national framework for transmission access reform given the significant impact of renewable energy zones (REZs) being developed by each jurisdiction?	The transmission access reform model options would support and strengthen jurisdictional REZ schemes. State governments have sought to promote more co-ordinated system development by establishing REZs within their regions. While access within each REZ can be managed through a jurisdictional REZ arrangement, the overall value of a REZ is subject to the broader access to the national grid. Under the current open access regime, participants can still connect to the grid at any point outside the REZ. In many cases, that connection could reduce the access available to parties in the REZ and degrade the value of connecting within

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

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		the REZ. It is also possible that a well-placed connection outside of the REZ could gain preferential access in dispatch. In this way, the current access regime gives rise to a version of the "tragedy of the commons", comparable to the use of water resources or global fishing stocks. Some jurisdictions plan for generators to help fund the cost of the REZ transmission infrastructure. There may be little incentive to participate in the government tender processes if generators have the option of locating just outside the REZ for free, and getting the same benefits – as they would under the current access regime. Alternatively, generators may be hesitant to fund REZ transmission infrastructure knowing their output may be constrained due to congestion outside the REZ. Transmission access reform also creates incentives for storage and flexible loads (such as hydrogen) to locate in REZs and operate in ways that alleviates congestion. At present, storage and flexible loads face the same price wherever they are in a State, which means they have no reason to locate in places where they could provide most value to the grid, nor to operate in ways that soak up surplus energy. Fewer subsidies would be required to underpin investments if we introduce reforms that reward storage and flexible loads for the valuable services that they provide. Section 3.2 of the Directions Paper provides more detail on how the reforms integrate with jurisdictional REZ schemes.
3. General	Why not simply ban new connections in congested areas?	Access goes to the heart of the market design and as such, it affects several aspects of market outcomes. Banning new connections in congested areas could help to provide locational signals and investment certainty, but it does not drive efficient dispatch outcomes, or reward storage for offsetting transmission costs. The hybrid model gives market participants more flexibility and autonomy than an approach that imposes caps on connections. Generators that wish to connect in congested locations can still do so, but they would face a lower priority in dispatch (under the priority access variant) or incur higher congestion fees (under the congestion fees variant).
4. General	Customer representatives have referred to the "build, constrain,	To protect consumer and taxpayers' interests, it is vital that we use our existing and new infrastructure efficiently. If we use our assets wastefully, we will need to invest more to achieve the same level of reliability, security and decarbonisation benefits.

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	complain"[2] model of transmission investment which passes the costs of congestion from generators to consumers. How does the transmission access reform avoid this cycle?	• The queue position requires new generators to take into account the costs they impose on others when they invest in projects which increase congestion. It addresses the risk that a generators' revenues are cannibalised by another generator that connects after them. • Congestion fees provide incentives for the efficient location and design of new projects i.e. incentivise developers to minimise the unit connection cost and progress projects of the right design and scale at the right location on the grid. • The CRM encourages providers of congestion relief (such as storage and flexible loads) to locate in congested parts of the network and operate in ways that minimises total system costs. The reforms would be designed to align with jurisdictional guidelines and procedures for their REZ schemes.
5. General	Clare Savage was recently quoted saying that we have developed an "incredibly complex market" in the "naïve belief that it would deliver the best outcomes for all consumers".[3] Does the ESB's hybrid model and technical design compound the complexity of the energy market?	The hybrid model does not affect a household customer's experience of their electricity bills and the options available to them. Under the model, the customer ultimately benefits from lower prices if transmission and generation investment is efficiently coordinated. The hybrid model does affect the development of projects and the wholesale markets, which are engaged by experienced investors and market participants. We accept the access reform is a significant reform and market participants will need time to adjust to the change. It relates to an aspect of the market that is intrinsically complex. The hybrid model and its proposed variants have been designed to integrate with the current market design and regulatory framework with which participants are familiar.
6. General	Is a hybrid model needed or does a model applied to either investment *or* operational timeframes materially resolve the congestion issues?	The investment and operational models are addressing two components of the problem. • Investment: The level of congestion in the system is consistent with the efficient level. • Operational: When congestion occurs, we dispatch the least cost combination of resources that securely meets demand.

[2] Energy Users Association of Australia, https://www.energy.gov.au/sites/default/files/2022-06/EUAA%20Response%20to%20transmission%20access%20reform%20Consultation%20Paper%20May%202022.pdf, 10 June 2022

[3] https://www.aer.gov.au/news-release/towards-energy-equity-opinion-piece-from-aer-chair-clare-savage, 20 October 2022

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		Our current market design does not have strong locational signals in investment timeframes to: • Efficiently coordinate generation and transmission investment • Discourage new entrants from locating in areas of the network that cannibalise existing VRE assets • Incentivise storage and flexible load to locate in the optimal locations. Under the optimal development path in the 2022 Integrated System Plan (ISP), AEMO forecasts we require approximately $250 billion of capital expenditure on new generation and transmission infrastructure out to 2050.[4] At this level, a 1% cost increase as a result of inefficient coordination of transmission and generation investment equates to additional costs of $2.5 billion, which are ultimately passed to consumers. The scale and cost to consumers of the optimal development path is already significant. It is vital that we use our existing and new infrastructure efficiently to protect consumer and taxpayers' interests. Our current market design does not currently have the price signals in operational timeframes to: • Encourage cost reflective bidding in the face of congestion so that the dispatch engine can solve for the lowest cost solution • Reward storage and flexible load for providing congestion relief. Even in a power system dominated by VRE generation, there will still be costs to congestion. The volume of unused available VRE in the REZs as a result of curtailment increases from 1 TWh to 21 TWh between 2025 and 2050 (excluding economic spill). There will be higher levels of curtailment at a low price point in future but there will actually be a total higher value given the significant increases in the volume of curtailment. Storage and flexible loads will become a more critical part of our mix of dispatchable generation and demand response. Storage capacity is forecast to increase by 30-fold between 2022 and 2050 under the ISP's optimal development path. Transmission access reform is designed to value and reward these assets for providing congestion relief services that have

[4] AEMO, 2022 Final ISP Results Workbook – Step change. Discounted total system costs, Candidate development path 2. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/generation-outlook.zip?la=en

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		benefits to the whole system. If we don't have a market to value these services, we may need to subsidise their investment.
7. General	Why is the ESB pursuing a hybrid model without international precedent? Should we instead adopt an accepted practice of locational marginal pricing (LMP) and financial transmission rights (FTR)?	There is no silver bullet to manage and solve congestion issues. Each international market has its own market design, generation mix and network complexities. International access models have been tailored to their individual circumstances and policy objectives. Ultimately, the design of the congestion relief market (CRM) aligns with a fundamental principle of any congestion model in the separation of 'access' and 'physical dispatch'. The CRM design separates access and physical dispatch because it allows for an incremental dispatch that is priced at the LMP. It comprises: • the current energy market (NEM dispatch) priced at the regional reference price (RRP) • a dispatch adjustment market (CRM) priced at the LMP. The AEMC and the ESB have previously considered the LMP/FTR model. Stakeholder concerns for the LMP/FTR model related to the potential increased complexity, heightened investment risk and reduced contract market liquidity. The CRM design helps to address these concerns: • The CRM is an adjunct to the existing energy market. It adopts a similar design to today's NEM which requires participants to submit energy and ancillary service bids. • Participation in the CRM is voluntary. It provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements.
8. General	When will the ESB release its cost benefit analysis (CBA) of the different model options? Will this CBA include the congestion management model?	The ESB is undertaking a CBA for all four model options (CRM, CMM, priority access and congestion fees). We plan to finalise the CBA in Q1 2023 which will incorporate stakeholder feedback on the design choices and include updated implementation cost estimates from AEMO. Outcomes of the CBA will inform the ESB's draft recommendations to Energy Ministers.
9. General	What are the impacts of model options for the financial markets and contract arrangements?	In today's energy market, congestion risk is borne by generators and the costs are ultimately passed to consumers in the form of risk premiums for contracts and/or retail prices. Congestion risks can be challenging to manage given the unpredictability of dispatch outcomes and the uncertainties of new incoming generation projects.

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		The hybrid model proposes two key variants to manage this congestion risk (with priority access or via a congestion fee). Within this model, there are a number of design choices to refine this ability to redistribute congestion risk and reduce revenue volatility. A summary of impacts is provided below. Priority access – a connecting generator would be assigned a queue number to determine its priority access in the energy market. The higher the queue number, the lower the dispatch priority. There would be implications for the generator when securing financing and negotiating contracts. The priority access variant increases the level of confidence of the curtailment risk faced by a project, and its access to the RRP. It will inform due diligence processes for equity, debt and contract negotiations. Congestion fees – a connecting generator may be required to pay a one-off congestion fee which is calculated as part of the connection process (but may be recovered over time). It would form part of the development costs for a new project. Depending on the governance arrangements, it may form part of the connection agreement with the relevant TNSP. CRM – The CRM was designed to address stakeholder concerns about the impacts on the contract markets. It gives market participants the opportunity to opt out. The CRM design (with or without priority access) can result in better or equivalent financial outcomes to the current energy market dispatch. It is expected that some contracts will be modified to allow contracting parties to share in the profit gains from the CRM. Where this cannot be achieved, the opt out principle provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements. Appendix D of the Directions Paper outlines the impact of the CRM on contract arrangements.
10. General	Is disorderly bidding a sufficiently material problem to justify the cost and complexity of the proposed solution?	To date, there have been two key drivers of disorderly bidding: • 5/30 problem whereby market participants are required to bid every 5 minutes, but the price was previously averaged out for the purpose of settlement

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		• Congestion whereby constrained generators bid to the market price floor to maximise their dispatch if their costs are less than the regional reference price Since October 2021, the 5 minute settlement rule was implemented and has led to reduced instances of disorderly bidding.[5] The issue of disorderly bidding in response to congestion remains unresolved. It is forecast to become a more material issue as the national electricity market transitions and the level of congestion increases. To accommodate approximately 135 GW of utility-scale VRE by 2050, the forecast economic spill is 15% and transmission curtailment is approximately 5%.[6] These levels can be considered the best-case scenario – they reflect what would occur if the power system develops with perfect foresight in line with the optimal development path. Access reform has a range of objectives that go beyond addressing disorderly bidding. There are also substantial potential benefits in providing improved locational signals to investors, and in providing incentives for storage and flexible loads to locate in places, and operate in ways, that provide greatest benefits to the power system.
11. General	Why do we need to solve for dispatch efficiency when race to the floor bidding is costless if it only affects zero marginal cost generators?	Even in a wholly VRE power system, there will always be a need for some form of dispatchable plant (such as storage) to manage intermittency. Under the current market design, this plant may be rewarded for competing with and displacing VRE during periods of congestion. Under the least cost power system design set out in the ISP, storage is often located in REZs so that it can offset the need for transmission investment. If we build a least cost power system, batteries will be competing with VRE to get dispatched.
12. General	Are congestion locational signals required given the signals already provided by marginal loss factors (MLFs)?	MLFs and congestion are two different things. MLFs measure energy that is "lost in transit", whereas congestion occurs when energy is unable to be dispatched because there is insufficient transmission infrastructure to transport it. Investment decisions that are guided by MLFs may still be poorly located from a congestion perspective.

[5] AEMO, Quarterly Energy Dynamics Q4 2021, https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en, p.15

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

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13. General	How will the continued growth in rooftop solar leading to constraints affect these models?	The models apply to scheduled and semi-scheduled generators and exclude non-scheduled generators (i.e. <5MW which typically applies to rooftop solar). Congestion in the distribution network is subject to parallel reform pathways, including the Distributed Energy Integration Program. Congestion management does not refer to economic spill. Rooftop solar will lead to lower prices during periods of high VRE.
14. General	What is the difference between locational marginal prices and pay-as-bid?	The NEM is currently based on regional pricing (also known as zonal pricing) which involves a 'pay-as-clear' mechanism. The CRM would introduce locational marginal prices for the purpose of settling CRM dispatch adjustments. The Directions Paper does not propose to introduce a pay-as-bid auction design. *Regional reference price (RRP)* is the spot price at which the energy market clears in today's market design. It is specific to its regional reference node (RRN). It represents the change in the cost of dispatch if one more MWh of load is needed to be supplied at the RRN.[7] It is often described in terms of a bid stack whereby all bids are compiled, and generators are dispatched from cheapest to most expensive. The marginal generator sets the market clearing price for all participants. *Pay as bid* is an alternate auction design. Generators are still dispatched from cheapest to most expensive according to their bids. But participants are paid their as bid price, rather than a uniform clearing price. *Locational marginal price (*LMP) is specific to each node of the network i.e. it is the change in the cost of dispatch if one more MWh is supplied at that location. A node typically refers to a single generator or scheduled load. If the node is constrained, the LMP is linked to the marginal costs of all the constraints affecting the node. LMP = RRP – congestion price The LMP is related to the RRP but it accounts for the cost of transporting electricity from the generator to the customer load.

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

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		If the node is unconstrained in the dispatch, the LMP is equal to the RRP (ignoring loss factors) i.e. transport prices are zero.
15. General	Would the reforms result in customers in different parts of a State paying different prices?	No. The vast majority of load would continue to pay the regional reference price. The exception would be scheduled loads, who are typically large industrial customers that have elected to participate in the wholesale electricity market. Scheduled loads would have the opportunity to lower their costs and/or earn additional revenue by participating in the congestion relief market.
16. General	When will the reforms be implemented?	We anticipate that any of the models – but particularly those that involve changes to the dispatch engine and accompanying market systems – will involve substantial, multi-year lead times. The time needed to implement the reforms will depend on which model is adopted, and the scheduling of other urgent changes to market systems. In practice, 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.
17. CMM	Why does the Directions Paper exclude the congestion management model (CMM) from its detailed design choices compared to the three other shortlisted model options?	The CMM shares a lot of the mathematical formulation, economic principles and dispatch efficiency benefits as the congestion relief market (CRM). However, the CMM had comparatively weaker support in submissions to the ESB's previous consultation paper (May 2022). The CRM has the potential to deliver additional benefits that address stakeholder's concerns with the CMM: • It enables market participants to manage their exposure to LMPs, by automatically allocating access to the RRP in the same way as under current arrangements • It gives market participants visibility of access and dispatch outcomes in pre-dispatch and real time, rather than in subsequent settlements. • It provides a more straightforward basis for hedging contracts with congestion relief providers. • It includes an 'opt out' feature that provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements. If it becomes apparent (during the detailed design phase and cost benefit analysis) that the CRM does not provide additional benefits that are commensurate with the

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		additional complexity and cost, the ESB proposes to revert to the CMM.
18. Priority access	How does the priority access variant (with queue positions) compare to the applications and queuing policy applied in Western Australia for new connections?	The priority access variant (with queue positions) is a different concept to the queuing policy in Western Australia's South West Interconnected System (SWIS). The priority access variant applies a queue position to determine which generator has a financial right to access the regional reference price (RRP) in the event of a market price floor bid. Western Australia's market design relates to a physical access right whereby generators are preferentially dispatched above other congestion-causing generators that do not hold a right. *Priority access variant in the Directions Paper* Priority access does not inhibit a new entrant from connecting to the network (subject to the existing connections process and Generator Performance Standards). The queue position does not determine the timing of connection. Instead it affects dispatch outcomes in the real time energy market. In the event of bids being tied at the market floor price, the queue determines which generators receive access to the RRP. The queue position applies in the energy market. It does not apply in the CRM. If a more efficient physical dispatch can be achieved, the CRM provides a mechanism to share profits from the efficiency gain. *Background to Western Australia's SWIS* The SWIS has operated as a notionally unconstrained access regime, where generators were granted firm access rights through their access contracts with Western Power. This encountered challenges when contracted network capacity reached system limits, leading to various bolt-on solutions. The original access arrangements for generators in the SWIS included a declared sent out capacity (DSOC), which required Western Power to provide the generator with access to that level under system normal conditions. This implied a 'do no harm' arrangement for new connections, which must fund augmentation as necessary to avoid impinging upon existing access rights. New connecting parties were offered the choice of: • A reference service, which may entail substantial deep connection costs (potentially $100 of millions) or

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		• A non-reference service, which may entail reduced access rights (i.e. curtailment). Once the network was full, connecting generators were faced with extremely high deep connection costs in order to receive firm access. Non-reference services (i.e. agreeing to curtailment) generally included a post-contingent runback on a "last-in, first out" basis. The proliferation of post-contingent runback schemes reached its limit in terms of complexity, leading to the introduction of pre-contingent runback arrangements. Key criticisms of this approach were that curtailments based on access contracts resulted in less efficient dispatch, and curtailment driven by off-market arrangements degraded the accuracy of pre-dispatch forecasts. As a result of the challenges encountered under a physical access regime, the SWIS is being converted to an open access regime, commencing October 2023, coincident with the introduction of a security-constrained, co-optimised real time market.
19. Priority access	Will the priority access variant stifle new entry?	Our preliminary view is that it would not deter efficient new entry. Indeed, the 'first in best dressed' dynamic has the potential to accelerate new entry. The access granted by the queue rights reflect the availability of hosting capacity; they adjust in accordance with prevailing network conditions and local generator output. To the extent that there is spare network capacity available at any given time, new entrants can use it. They can also be dispatched via the CRM if there is a lower cost outcome. Each generator is protected from subsequent wealth transfers to future investments, reducing their risk when compared to the status quo open access regime. A new project may be prepared to absorb higher levels of curtailment in the short term to take advantage of new hosting capacity when it becomes available. But if the new project's business case relied on cannibalising access from incumbents in the medium to long term, arguably it should not be connecting at that location. Put another way, queue positions that have most value are most likely to be in parts of the network that are – or are expected to be – uncongested. This incentivises generators to join the queue in these areas, promoting efficient investment. The Directions Paper includes a number of design choices on the balance of interests between new entrants and incumbents. These include the role of grandfathering, whether rights should be auctioned, the duration of the

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		rights, and whether the level of congestion faced by priority queue rights holders should be designed to increase over time in line with the efficient level of congestion in the system.
20. CRM	The congestion relief market (CRM) is a voluntary market. How will this reform ensure that we achieve an efficient market outcome? What is the probability weighting applied to benefits to offset the implementation costs?	The CRM is a new energy adjustment market that enables participants to achieve an incrementally more efficient dispatch and share the efficiency gains as increased profits. Participants are incentivised to opt-in otherwise they may forfeit potential profits available. In the short term, generators may opt-out if they are managing contract arrangements linked to physical generation. In the medium to long term, we expect that contracting parties will amend the contract terms to take advantage of the CRM and share in the profits available. The opt-out principle provides a natural pathway to navigate contract arrangements from the existing to future market design without needing to implement complex transitional arrangements. The ESB has contracted a scope of modelling work to quantify the impact on system costs based on a partial and full participation of the CRM. For the purpose of the CBA, a full level of CRM participation is expected given the financial incentives. Sensitivities will be developed in response to this opening assumption. It is assumed that participants will opt in if the benefits of participation exceed any associated transaction costs.
21. CRM	What kind of bids would a participant submit into the CRM?	A concept of 'buying' and 'selling' CRM adjustments has been discussed either as (a) an early iteration of the CRM design or (b) to explain the principles as to how the CRM market clears. However, it is expected that the bids would be similar in requirement and format as per the energy market bids i.e. participants would offer full CRM supply / demand curves for their capacity. The difference is that the participant would be paid at its LMP for the CRM adjustments compared to the RRP for its energy market dispatch. Given that the CRM could increase or decrease a participant's dispatch and CRM adjustments are priced at the LMP, the participant would be incentivised to bid at its cost in the CRM. Bids into the energy market are likely to be much the same as they currently are but bids into the CRM would be expected to be cost reflective.

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22. CRM	The Directions Paper includes a design choice on the calculation of RRP referred to as RRP_{NEM} and RRP_{CRM}. How is RRP_{CRM} calculated?	It is proposed there would be two sequential NEMDE dispatch runs for each five minute dispatch interval: • Energy market dispatch based on energy market bids • CRM dispatch based on CRM bids This means that the CRM dispatch is a full dispatch but for settlement purposes, only adjustments between CRM and NEM are settled at the LMP. The RRP can be calculated from the CRM in the same way as it is in today's energy market. The RRP may differ between the two markets given: • differences in bids • changes in demand from storage acting as load, or scheduled loads choosing to participate in the CRM • changes in interconnector flows. An earlier iteration of the CRM design had proposed a co-optimisation model between the energy market and CRM (similar to other ancillary service markets). However, this solution would have involved more substantial changes to NEMDE and would have increased solve time. This approach also had the potential to result in disorderly bidding behaviour in the CRM for the units which had chosen no deviations between the energy dispatch and the CRM dispatch in order to get a better outcome in the energy dispatch. In this case, even though these units would not be practically participating in the CRM their behaviour in the CRM could distort the outcomes in the energy dispatch. The sequential dispatch allows NEMDE to solve and gives confidence that it replicates the same NEMDE structure and algorithms and minimises changes required to NEMDE. It preserves the optionality of the CRM. For participants that opt-out of the CRM, it is intended that their dispatch outcomes from the energy market would be 'locked' for the purpose of the CRM dispatch immediately after. The technical implementation plan is being developed to give effect to this principle.
23. CRM	Table 13 of the Directions Paper (p.55 Two options for the calculation of the RRP) includes a formula for unconstrained generator revenue. Please can you clarify this formula?	Table 13 referred to constrained generators and unconstrained generators. These categories refer to: • Constrained generator – participant on the LHS of a binding constraint • Unconstrained generator – not part of any binding constraint. Given the CRM dispatch is a full dispatch, it is expected that constrained and unconstrained generators would participate

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		in the CRM. Detailed modelling of the proposed CRM design has shown that participation in the CRM is expected to be broader than small numbers of participants behind a common single constraint. This is often true when congestion is located near regional boundaries and there are CRM adjustments to interconnector flows (affecting constrained and unconstrained generators on both sides of the boundary). Table 13 referred to the following formula in Option 1: Generator revenue (unconstrained) $= G_{NEM} \times RRP_{NEM} + G_{ADJ} \times RRP_{CRM}$** This formula is equivalent to the following: $= G_{NEM} \times RRP_{NEM} + G_{ADJ} \times LMP$ *Given LMP = RRP – congestion price, and the unconstrained generator is not part of a binding constraint, this means the congestion price = 0 and thus the generator's LMP from the CRM = the CRM's RRP* $= G_{NEM} \times RRP_{NEM} + G_{ADJ} \times RRP_{CRM}$ Where: G_{NEM} dispatch of a unit from the energy market G_{ADJ} dispatch adjustments from the CRM = $G_{CRM} – G_{NEM}$ RRP_{NEM} RRP from the energy market RRP_{CRM} RRP from the CRM dispatch LMP LMP for the unit from the CRM dispatch
24. CRM	Will CRM settlements always balance to zero?	Preliminary modelling has demonstrated that there are likely to be CRM settlement residues. A constraint equation is a linear equation with a Left Hand Side (LHS) and a Right Hand Side (RHS)) that talk to the NEM dispatch engine (NEMDE) to ensure the market solutions are within the physical limit of the power system.[8] This occurs for constraints where LHS_NEM < RHS due to the location of congestion changing between the two dispatches ie the constraint is binding in CRM dispatch but not energy dispatch.

[8] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/constraint-faq

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25. CRM	Will rounding constraint coefficients in the energy market lead to an insecure dispatch and/or settlement deficits in the CRM?	The Directions Paper proposes a design choice to round constraint coefficients in the energy market. Rounding would not be applied in the CRM. When the LHS of the constraint is less than or equal to the RHS, there will not be any settlement deficits in the energy market or CRM dispatches (LHS ≤ RHS). Rounding introduces: • True_LHS: LHS calculated using precise coefficients • Rounded_LHS: LHS calculated using rounded coefficients Rounded_LHS will always be less than or equal to the RHS. But True_LHS could be higher than the RHS (where Rounded_LHS ≤ RHS < True_LHS). In this case: • if there is no dispatch adjustment in the CRM (eg because of opt-out), physical dispatch would be insecure; and • if there is dispatch adjustment in the CRM to ensure security, this could lead to a deficit in CRM settlement. ESB is currently investigating: • whether these instances of insecure dispatch would arise given the prevalence of "feedback" constraints that would self-correct any errors or approximations in the coefficients • and, if these instances would arise, how to maintain security in the final dispatch on the assumption there is insufficient CRM participation. The Directions Paper noted that if a secure dispatch cannot be achieved with rounding, a subsequent trade-off decision will be needed between relaxing the rounding or relaxing an alternative constraint. If there is a deficit in the CRM settlement, the settlement residue should be more than sufficient to fund any small deficits caused by rounding.