TRANSPOWER

Evolving market resource co-ordination: Tie-breaker provisions

Consultation Document

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IMPORTANT

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1 Executive Summary

1. Transpower, in its role as System Operator, is seeking feedback on how tie-breaker situations should be resolved for multiple competing generator offers in the wholesale electricity market. A tie-breaker situation arises when more, equally priced generation is offered at a single location than can be dispatched due to a network export limit. These situations are emerging in the market, and while not yet widespread or frequent, we are observing them in practice. As a consequence, generator owners and investors are increasingly seeking clarity and confidence on how tie-breakers are or will be resolved by the System Operator.
2. Currently, the resolution of tie-breaker situations is unprescribed and may result in the System Operator applying its discretion, close to or in real-time, to decide which generator(s) to dispatch and for what quantity. This has the potential to result in uncertain, inconsistent and unpredictable dispatch decisions that create operational challenges and undermine investor confidence. As incidences of tie-breaker situations increase in frequency this risk will be exacerbated. Consequently, we are consulting now to provide greater certainty ahead of time.
3. This consultation paper sets out the System Operator's proposed solution for resolving tie-breaker situations, and alternative options we have also considered.
4. Our proposed solution introduces a tie-breaker energy constraint within the Scheduling, Pricing and Dispatch (**SPD**) model that allocates dispatch at a given pricing node in proportion to offered quantities. In our view this method strikes the balance between certainty, transparency and simplicity, and limits the need for System Operator discretion to be applied.
5. We invite feedback from industry participants and interested stakeholders on:
   - our proposed solution, and the feasibility, operational implications, and potential unintended consequences of it;
   - the alternative options, particularly if you think they might provide a better solution than our proposed solution;
   - any other potential solutions you think we should also consider; and
   - whether transparency and certainty about any tie-breaker solution we implement should be enhanced by incorporating elements of it into the Policy Statement.
6. We plan to progress the next Policy Statement review during the year ending June 2026. This will include consultation on draft proposed amendments ahead of any final amendment proposal being submitted to the Electricity Authority (**Authority**) for its consideration. Only the Authority can approve an amendment to the Policy Statement.
7. Your feedback will inform our decision on whether to progress to implement the proposed solution, (or a modified form of it), into our tools and processes. If we decide to proceed to implementation it could be in effect during the first half of 2026. If we instead decide to consider alternative options or approaches further we are likely to re-consult on a different proposed solution. Once we have considered the feedback we receive in response to this consultation we will publish our summary of submissions and the decisions we have reached having considered your feedback.

2 Introduction

2.1 Purpose of this consultation

8. The purpose of this consultation is to seek feedback on our proposal how tie-breaker situations should be resolved for multiple competing offers in the wholesale electricity market. We invite your feedback on:

   - our proposed tie-breaker solution, and the feasibility, operational implications, and potential unintended consequences of it;
   - the alternative options, particularly if you think they might provide a better solution than our proposed solution;
   - any other potential solutions you think we should also consider; and
   - whether transparency and certainty about any tie-breaker solution we implement should be supported by incorporating elements of it into the Policy Statement, which could be progressed through a subsequent review of the Policy Statement.

9. Your feedback will inform our decision on whether to progress to implement the proposed solution, (or a modified form of it), into our tools and processes. If we decide to proceed to implementation it could be in effect during the first half of 2026. If we instead decide to consider alternative options or approaches further, we are likely to re-consult on a different proposed solution.

10. Once we have considered the feedback we receive in response to this consultation we will publish our summary of submissions and the decisions we have reached having considered your feedback.

2.2 Consultation process

11. The consultation period is 3 weeks commencing on Thursday, 24 July 2025. Submissions are due by 5pm on Thursday, 14 August 2025. This is followed by a one-week period of cross-submissions. Cross-submissions are due by 5pm on Thursday, 21 August 2025.

12. Please send submissions to system.operator@transpower.co.nz. We will acknowledge receipt of all submissions. Submissions will be published to our website at System Operator Consultations | Transpower

13. If your submission or cross-submission contains confidential material, please ensure this is clearly identified and provide a version of your submission or cross-submission that can be published. Transpower takes no responsibility for identifying confidential information.

14. Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982.

2.3 What is a tie-breaker situation?

15. A tie-breaker situation in electricity markets occurs when multiple generators offer, or purchasers bid (through dispatchable demand), at the same location with the same price, and not all parties can be dispatched to their economic maximum because of a network export, or import, limit. The market-clearing process must determine how to allocate dispatch between the generators, or purchasers, causing the tie-breaker situation.

16. Currently, a tie-breaker situation at a single pricing node[1] may require resolution in real time by the System Operator applying discretion to allocate the available dispatch capacity between those generators or purchasers. While SPD[2] will solve the market optimisation as it is required to (see Section 3), it is uncertain ahead of time what solution it will schedule. This is because all possible solutions in a tie-breaker situation are equally optimal. One offer may fully clear while another may partially clear. These outcomes are non-deterministic and can vary from interval to interval and schedule to schedule.

17. If System Operator discretion is needed, those decisions are typically guided by system security considerations, such as generation certainty and physical system needs. This tends to happen particularly for inflexible generators with start-up requirements or minimum operating levels. For example, an inflexible plant may be scheduled on in forecast schedules but dispatched off or below its minimum level in real time, requiring coordinators to assess potential security impacts and apply discretionary constraints to keep the plant on for critical periods. The proposed tie-breaker solution would not prevent the potential for this to occur.

18. Implementing an effective tie-breaker mechanism would ensure consistent, efficient, transparent and predictable dispatch outcomes, while reducing reliance on discretionary interventions by the System Operator.

2.4 An effective tie-breaker solution is needed now

19. The growth of intermittent renewable generation, including generation embedded in distribution networks, increases the likelihood of such situations, such as when demand is low and renewable generation is high nationwide or when transmission constraints bind in regions with high renewable generation export capacity.

20. We're receiving more queries from generation investors seeking clarity on how tie-breaker situations are handled. The lack of a consistent approach creates uncertainty for operations and investment.

21. Transpower, as System Operator, previously consulted on this matter as part of a White Paper on "Evolving market resource co-ordination in Aotearoa New Zealand" published on 3 July 2024. Feedback was due by 30 July 2024, and we continued to receive submissions until 19 August 2024.[3]

22. In our response to submissions, we concurred with Contact Energy's suggestion of a broader study to address how "oversupply of must-run generation" is resolved. In response, we assessed a range of potential alternative options, including those proposed in submissions. We selected our proposed solution, and tested it by successfully developing a tie-breaker energy constraint in SPD to allocate output proportional to generators' offers. We have engaged with the Authority as part of progressing this work.

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1 In situations involving multiple pricing nodes (e.g. regional), loss factors help establish deterministic MW allocations in the forecast schedules, providing generators with greater certainty and allowing potential issues to be resolved ahead of real time. These scenarios are outside the scope of this consultation.

2 Further description of the SPD model can be found here - Software specifications | Transpower and an overview of SPD can be found here - SPD101 | Transpower.

3 The consultation paper, submissions and our response to the feedback we received are available on our webpage: Evolving market resource co-ordination in Aotearoa New Zealand (Closed) | Transpower

3 Problem definition: current market design challenges

23. The Code requires the System Operator to schedule and dispatch generation to maximise the gross economic benefits for all purchasers. This requirement is placed by the Dispatch Objective[4] and is subject to the offered capacity of the transmission grid and dispatched resources, achieving the Principal Performance Obligations (**PPOs**) and the needs of restoration. The System Operator may apply further constraints on the dispatch solution to comply and plan to comply with the PPOs. Particularly, the constraints applied should allow the System Operator to ensure transmission assets do not become overloaded, and the system remains in a stable operating state. Ensuring a consistent dispatch solution is important to meeting these criteria and avoiding unexpected system configurations.

24. In a tie-breaker situation SPD has multiple possible solutions which meet the dispatch objective, and importantly SPD has no prescription about which solution to choose. Any combination of the same priced offers, or bids, can be scheduled equal to the export, or import, limit and the dispatch objective is met.

25. The Must Run Dispatch Auction (MRDA) allows generators to improve their chances of being dispatched by securing rights to offer at $0/MWh. However, as the MRDA operates at a national level, it does not specifically account for regional transmission constraints.

26. Introducing negative price offers to the market design could support more granular price differentiation, particularly across different types of generators. We would expect this to reduce the frequency of tie-breaker scenarios occurring.[5] However, any work to consider implementing negative price offers is a matter for the Authority, and it would also require moderate change to the System Operator's market system. In any case the need for a tie-breaker mechanism would remain since the potential for too much same-priced generator offers at a particular connection to the grid would remain.

3.1 Issues with current design

27. Normally generation curtailment would be realised economically in the dispatch solution. However, where export capacity and/or demand is limited and there is no cost differentiation, an SPD solution may schedule inconsistent proportions of generation from generators offered at the same pricing node, i.e. which offer will fully clear or partly clear is not deterministic, and can change from interval to interval, schedule to schedule.

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[4] Clause 13.57 of the Code describes the Objective Function, which is encoded into SPD as the outcome it must achieve. Further details on the Objective Function and modelling system (SPD), including a mathematical representation of the Objective Function, are contained in Schedule 13.3 of the Code.

[5] Currently there is a $0/MWh minimum offer price floor. The Market Development Advisory Group (MDAG) recommended Code amendment to allow negative offers/prices (Tranche 3/Recommendation 29) as part of its "Price discovery in a renewables-based electricity system – FINAL RECOMMENDATIONS PAPER", 11 December 2023.
The Authority has committed that the MDAG recommendations in tranches 2 and 3 will be considered and incorporated into its work programme in due course: https://www.ea.govt.nz/news/general-news/authority-finalises-response-to-mdag-report/.
Enabling negative price offers could be considered as part of future market design discussions.

28. It is operationally difficult for the System Operator to manage the power system when generation changes substantially and inexplicably between forward schedules and real-time dispatch. It also may cause considerable operational difficulty for generators themselves, especially relatively inflexible "must-run" renewable plant like geothermal as well as thermal plants that require minimum start-up times.

29. In addition to operational impacts, the current randomness is also inequitable. Generators with identical offers can receive significantly different dispatch outcomes. This creates uncertainty, which may deter future investment in new generation if investors cannot reliably anticipate dispatch outcomes.

30. To ensure dispatch security and, ultimately, compliance with the PPOs, it is important that the forward schedules and dispatch schedules align as much as is reasonably possible. This alignment relies on the information input to the forecast schedules being sufficiently accurate to be adequately representative of real-time system conditions. While some divergence is inevitable due to changes in generation offers, asset availability, or the accuracy of forecast demand and intermittent generation output, System Operator coordinators actively monitor such deviations.

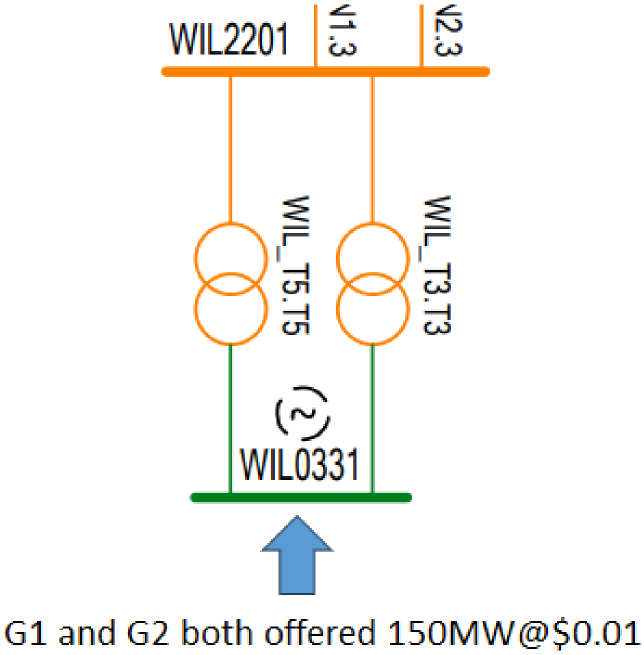
31. Improving the alignment reduces the need for discretionary interventions, supports reliable operational planning, and benefits inflexible generators. It also promotes fairness and investor confidence by ensuring consistent and predictable dispatch even under constrained conditions. It is therefore important to restrict the SPD solution to minimise randomness and ensure generation is scheduled consistently from one schedule to the next even if there may be no cost differentiation between assets offered at the same pricing node.

3.2 Materiality of the tie-breaker problem

32. Tie-breaker events currently occur infrequently. However, when they do occur, accurate and efficient outcomes are critical.

33. The issue is becoming increasingly important as new generators enter the market. New entrants seek certainty of MW allocation when building generation behind specific grid locations, increasing the need for a clear and predictable tie-breaker approach.

34. Using an offline version of SPD in a test environment we solved a non-response schedule (NRSS) which we had manually adjusted to create a tie-breaker situation; placing two generators G1 and G2 behind the WIL0331 GXP. The combined, identically priced, generation offers of G1 and G2 exceeded the export limit from the WIL0331 GXP. We observed the cleared MW allocations were distributed inconsistently between two generators (G1 and G2) during the 15:30 and 16:00 trading periods as shown in Figure 1. When two same-priced generator offers are located at the same bus behind a binding constraint, one generator may fully clear while the other only partially clears.



NRSS

15:30	Cleared MW
G1	150
G2	70.5
16:00	**Cleared MW**
G1	70.5
G2	150

Figure 1 Example of two same-priced generator offers with random dispatch outcomes in the NRSS schedule during the 15:30 and 16:00 trading periods

35. Which generator fully or partially clears is not deterministic and can vary between intervals within the same schedule, and even across successive schedules, as shown in Figure 2.

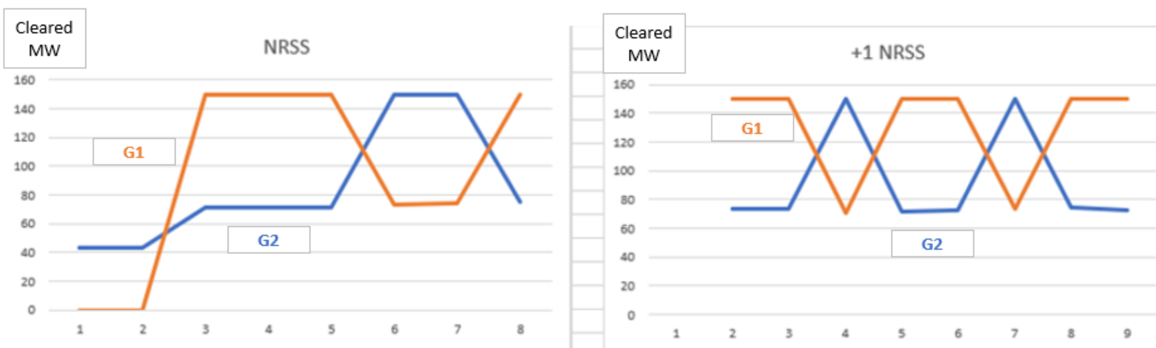


Figure 2 Example of random dispatch outcomes for two same-priced generator offers across successive NRSS schedules for the same trading periods

36. In real-time dispatch, the initial outcome is effectively random, potentially differing significantly from the NRSS schedule, but then remains fixed until the constraint unbinds. This is because SPD aims to minimise dispatch changes by continuing to select the same-priced generation already dispatched with no cost difference.[6]

37. For example, an inflexible plant can be scheduled on in the forecast schedules but then dispatched off or below its minimum operating level in real time. In such cases, coordinators must assess the

6 This policy exists to avoid unnecessary changes in generation output given every generation output change has an element of risk associated with it, and in these cases there is absolutely no benefit to the market or system of dispatching those changes.

potential security impacts on the system, particularly during peak periods, and may need to apply discretionary constraints to keep the plant on if necessary.

38. This inherent misalignment between forecast schedules to real time dispatch can create uncertainty for market participants, undermine investment certainty, and increase reliance on discretionary interventions by the System Operator.

4 Potential tie-breaker solutions

39. We have identified and assessed the following potential tie-breaker solutions, including those proposed in submissions to the White Paper on "Evolving market resource co-ordination in Aotearoa New Zealand". Options 5 to 8 reflect the ideas developed in our published response to submissions.[7]

    1) Dispatch in proportion to offers (our proposed solution).
    2) Re-solve in SPD;
    3) Singapore tie-breaker solution;
    4) Enforcing equal MW allocation;
    5) Prioritising different types of generation;
    6) Earlier submitted offers take precedence;
    7) Consider local distribution constraints;
    8) MRDA refinement.

40. This section sets out our consideration of these solutions.

4.1 Dispatch in proportion to offers (our proposed solution)

41. We have reviewed several tie-breaker mechanisms implemented in other jurisdictions, most of which are pro-rata based. This approach allocates MW in proportion to offered quantities in a simple, fair, and operationally practical manner. It has been successfully applied in other markets and is well-suited to nodal pricing environments. Further details are provided in the table below.

Country	System Operator	Tie-breaker mechanism	Description
USA	PJM	Operational factors - based	A system of tie-breakers prioritises bids/offers using factors like submission time, unit type, and historical performance.[8]
	ERCOT	Pro-rata basis	The logic is to pro-rata the energy awarded at the marginal offer to competing resources based on the MW of the resource's offer segment at the price.[9]
Canada	IESO	Time-Based (revising)	Currently uses earliest timestamp, but transitioning to a revised method considering 3 steps based on submission time, equal share, and pro-rata allocations.[10]
Ireland	EirGrid	Pro-rata basis	If multiple units have the same price, then the intention is to pro-rate between these units.[11]

7 Market Resource Coordination Consultation Responses

8 Page 97 and 98 - https://www.pjm.com/-/media/DotCom/documents/manuals/m11.pdf

9 https://www.ercot.com/files/docs/2012/05/01/write_up_of_over_mitigation_.doc

10 https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/cae/cae-20241118-design-memo-3-0-tie-break-methodology-2025.pdf

11 https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-SDP-Industry-Workshop-1-November-2023.pdf

Country	System Operator	Tie-breaker mechanism	Description
Australia	AEMO	Pro-rata basis	Pro-rata the MW quantities specified in the relevant price bands.[12]

Table 2 Summary of tie-breaker mechanisms implemented in other jurisdictions

42. We consider that this approach has a number of advantages including simplicity, operational certainty, and equity for market participants. We consider that clear and predictable tie-breaker rules would help reduce the need for discretionary System Operator interventions, improving transparency and market confidence.

43. Consequently our proposed solution is to handle generator tie-breaker situations at a wholesale market pricing node by dispatching generation in proportion (pro-rata) to their offered MW quantities[13] at that node.

Question 1:	*Do you support our proposed tie-breaker solution: dispatch in proportion to offers? Do you have any feedback on any aspect of it or our consideration of it?*

4.2 Re-solve in SPD

44. It is possible to implement SPD post-processing[14] to check for tie-breaker needs, create tie-breaker constraints to enforce a pre-determined pattern (e.g. equal proportion to offers), and then re-solve. However, this approach would introduce additional complexity to the SPD solution and is more complex to implement and engage with operationally than the preferred option.

45. In contrast, introducing an energy tie-breaker constraint[15] can address tie-breaker within the initial solve, eliminating the need for a re-solve. This approach has been successfully implemented and proven effective in practice.

4.3 Singapore tie-breaker solution

46. The intent of the Singapore approach appears to be the even distribution of generation to achieve the best overall outcome for all generators (regardless of location) offering the same price.[16] However, it does not account for situations where equally priced generation is located at a single node due to a network export limit. This may be driven by the fact that Singapore's market settles a uniform (non-nodal) pricing model rather than ensuring a fairer outcome for individual generators located behind a binding constraint.

47. As a result, the unmodified Singapore approach will not meet the objectives of tie-breaker in the New Zealand electricity market, where nodal pricing and locational fairness are key considerations.

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12 https://wattclarity.com.au/articles/2022/05/who-gets-to-run-when-everyone-bids-the-same-a-crash-course-in-disorderly-bidding-and-tie-breaking/

13 For intermittent generation, it means the allocation will be based on forecast of generation potential (FOGP).

14 Section 8 Post Processing in SPD formulation Software specifications | Transpower

15 D.20A in Appendix 6D Market Clearing Formulation (Part 2) https://www.home.emcsg.com/about-the-market/rules/market-rules

16 In paragraph 1.4.4 https://www.ema.gov.sg/content/dam/corporate/partnerships/consultations/policy-on-direct-supply-(18-nov-2009)/decision/EMA-Consultations-Final-Determination-Review-Policy-Direct-Supply-Electricity-Generating-Sets-to-Onsite-Loads.pdf.coredownload.pd

However, our proposed solution is based on the Singapore tie-breaker approach, refined to prioritise specific generators behind binding transmission constraints.

4.4 Enforcing equal MW allocation

48. Equal MW allocation distributes the constrained MW quantity equally among all affected generators. However, this approach alone may not work effectively when generators with significantly different capacities share a bus. For instance, if two generators have capacities of 10 MW and 100 MW and the export limit is 105 MW, an equal dispatch allocation of 52.5 MW each would not be achieved as the 10 MW generator cannot exceed its capacity. As a result, the equal MW allocation constraint would not apply, reverting the dispatch allocation to a random proportion. In these cases, a different tie-breaker solution would be required to manage the allocation, introducing additional complexity.

49. Additionally, equal MW allocation could overlook temporary de-ratings due to generation outages or other availability constraints. This could result in allocations that do not reflect the generators' actual short-term capabilities. This approach may also disincentivise investment in high capacity and more efficient plants, impacting long-term system reliability and economic efficiency.

50. Therefore, equal MW allocation alone is not a preferred solution because it is insufficient to address all tie-breaker scenarios, and its implementation would require complementary solutions, further increasing complexity in the SPD solution.

4.5 Prioritising different types of generation

51. Generator type prioritisation involves assigning priority based on generator characteristics, e.g. prioritising geothermal generation over intermittent sources due to its contribution to system inertia and generation certainty. This approach can support more efficient dispatch outcomes.

52. However, generator type prioritisation alone may not be sufficient because a different tie-breaker solution would still be required when dealing with the same type of generation, such as multiple intermittent generators at the same location. Therefore, this approach is not a preferred standalone solution. Its implementation would require complementary solutions, introducing additional complexity into the SPD solution.

53. Allowing negative price offers may support a more robust and transparent mechanism for prioritising different types of generation. This concept shows promise and could be worth the Authority exploring further in future design phases or market development initiatives.

4.6 Earlier submitted offers take precedence

54. Time-based resolution involves prioritising offers based on their submission time. However, relying solely on submission time raises concerns about the accuracy and relevance of earlier offers in tie-breaker scenarios. Furthermore, this approach may not be effective when offers are submitted simultaneously, which is likely under the upcoming hybrid forecasting arrangement for intermittent generators.[17] In this arrangement, intermittent generation offers could be coming from the centralised forecaster and submitted at the same time, limiting the effectiveness of using offer submission times for tie-breaker.

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[17] Hybrid forecasting arrangement for intermittent generators https://www.ea.govt.nz/documents/6576/Review_of_forecasting_provisions_for_intermittent_generators_-_final_Code_amendments.pdf

55. As a result, time-based resolution is not a preferred solution for managing tie-breaker situations.

4.7 Consider local distribution constraints

56. Considering local distribution constraints in a tie-breaker solution could enhance dispatch security and better reflect real world network limitations. However, this approach introduces significant complexity and cost, as it would require detailed modelling of diverse and currently less visible distribution networks, including tracking outages at the distribution level. The System Operator may also face challenges related to data availability and real-time visibility. Additionally, the risk of overcomplication could reduce transparency for market participants. Importantly, even if distribution constraints were considered, a tie-breaker solution would still be required.

57. As a result, incorporating distribution constraints into tie-breaker is not the preferred solution due to its high implementation burden and limited practicality.

4.8 MRDA refinement

58. This approach, suggested in one of the submissions, is based on a hybrid version of SPD designed to optimise complex and intertemporal conditional offers and bids. However, implementing this would require significant changes to both the current market design and the Market System, including SPD. While further regionalising the MRDA would shift the focus from national to regional optimisation, a tie-breaker solution would still be required to allocate MW in constrained situations. Given the high complexity and the currently unclear scope of changes required, this option has been discounted at this stage.

Question 2:	*If you do not support our proposed tie-breaker solution, which alternative option would you prefer? If so, please describe the alternative and why you prefer it.*

Question 3:	*Are there alternative options we have not identified which we should consider?*

5 We have tested our proposed solution

5.1 Prototype for dispatch in proportion to offers

59. We have developed a prototype for our proposed tie-breaker solution in SPD and tested it. The prototype applies an energy constraint in SPD to allocate impacted generators' output proportional to their offers at a market pricing node. This constraint is based on the Singapore tie-breaker approach, refined to prioritise specific generators behind binding transmission constraints. We have engaged with the Electricity Authority on this topic, demonstrated the prototype of the model, and shared a workable SPD solution.

60. The results of our prototype testing show that tie-breaker dispatch in proportion to offers at a node can be enforced for all offer quantities because there are no trade-offs with the offers at other pricing nodes. This method provides a simpler and fairer dispatch outcome because it still considers the relative size of each generator by dispatching generators proportionally to their offers and avoiding inefficiencies of strict equal MW allocation. Using the same example from Section 3.2, both G1 and G2 would be cleared to 110.2MW for the 15:30 and 16:00 trading periods as shown in Table 1.

Trading Periods	Generator	NRSS Cleared MW	Tie-Breaker Prototype Cleared MW
15:30	G1	150.0	110.2
	G2	70.5	110.2
16:00	G1	70.5	110.2
	G2	150.0	110.2

Table 1 Comparison of NRSS vs. Tie-Breaker Prototype Dispatch Outcomes

61. This proposed solution does not consider other services like reserves or frequency keeping. The key issue is that reserves should not be scheduled behind a binding constraint. Similarly, frequency keeping presents a challenge because the frequency keeper may need to generate beyond its dispatch point to maintain system frequency. Additionally, the selection process for frequency keeping is not currently resolved within the SPD. As a result, incorporating different types of services into the tie-breaker mechanism would introduce additional complexity to the SPD solution, and in some cases, may not be feasible due to binding constraints.

62. Assessing the effect of implementing the proposed solution is not easily quantifiable. Given that tie-breaker situations are likely to remain relatively infrequent, and the efficiency differences between alternative approaches are expected to be minor, we do not believe a quantitative assessment of benefits is justified. The preferred option has proven successful in other jurisdictions and we have tested a prototype solution successfully. It is expected to incur minor implementation costs, primarily associated with updates to the SPD model. The key benefits of the proposal are not easily measurable. They include benefits arising from greater certainty to inform investment decisions, operational certainty, equity for market participants, and reduced reliance on real-time discretionary decisions by the System Operator.

Question 4: Do you agree with our qualitative assessment that the benefits of the proposal can reasonably be expected to outweigh the costs?

Question 5:	*Do you agree it is appropriate to rely on qualitative evaluation of the costs and benefits of the proposed amendments? If not, what information, evidence etc can you provide and/or what methods would you recommend to quantify the costs and benefits?*

5.2 Certainty could be enhanced through the Policy Statement

63. We consider that transparency and certainty may be usefully enhanced by incorporating information about any tie-breaker solution we decide to adopt into the Policy Statement.

64. The process we must follow to propose amendments to the Policy Statement to the Authority for its consideration is set out in the Code. It includes engagement with the Authority and consultation with participants, on our draft Policy Statement amendment proposal. Only the Authority can decide to amend the Policy Statement.

65. We would incorporate tie-breaker situations as a topic for our next Policy Statement review, which we currently plan to progress during the year ending June 2026. This will include consultation on draft proposed Policy Statement amendments ahead of any final amendment proposal being submitted to the Authority for its consideration. Only the Authority can approve an amendment to the Policy Statement.

Question 6:	*Do you think we should progress a proposal to incorporate information about any tie-breaker solution we decide to adopt into the Policy Statement, to enhance certainty and transparency?*