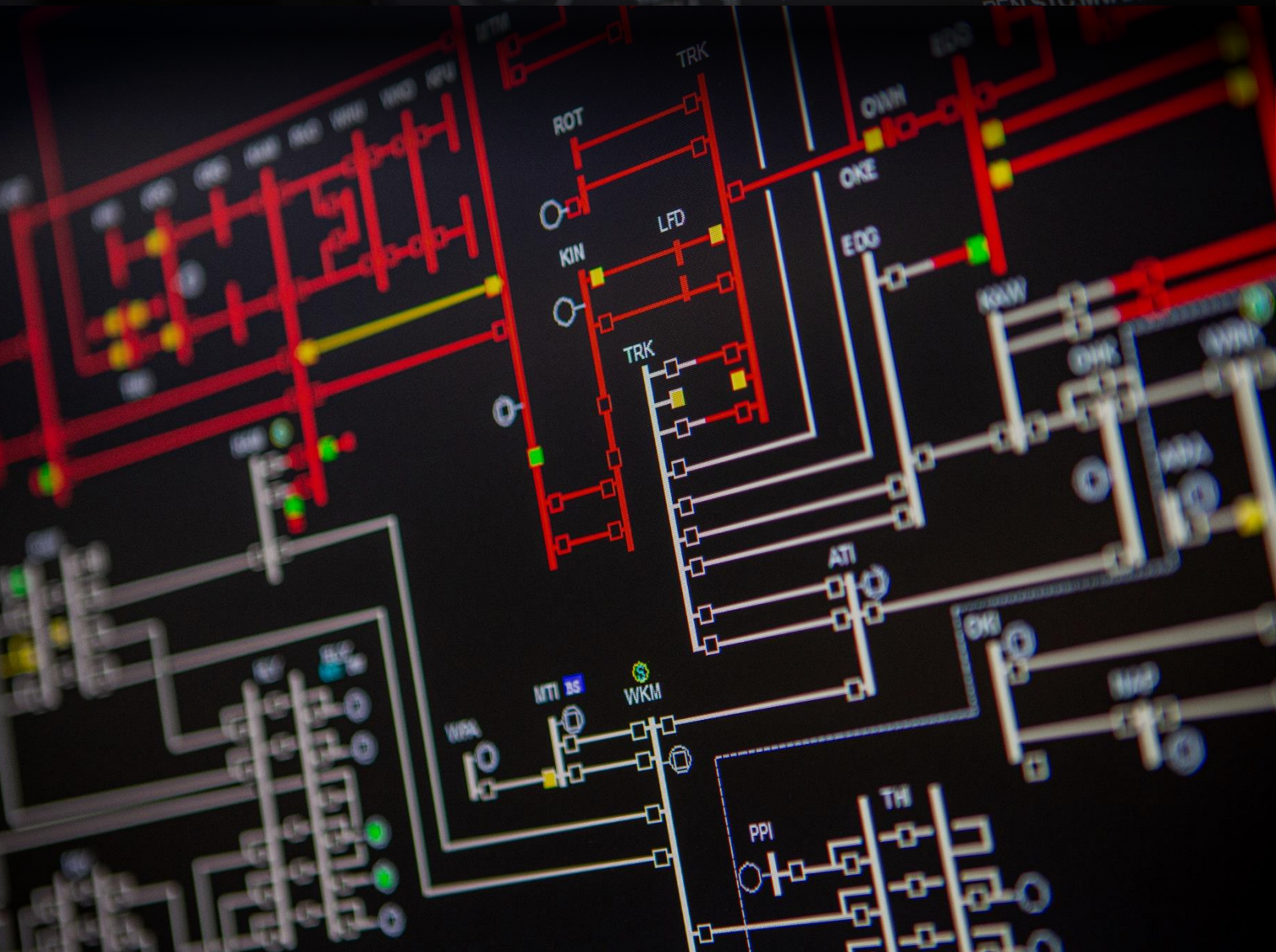




TRANSPOWER

Evolving market resource co-ordination Tie-breaker provisions: Summary and response to submissions

November 2025



1 Purpose

1. In July 2025, we invited feedback on our tie-breaker provisions consultation document.¹ Transpower, in its role as System Operator, was seeking feedback on how tie-breaker situations should be resolved for multiple competing generator offers in the wholesale electricity market.
2. The purpose of this Summary and Decision document is to present Transpower's decisions following review of submissions and cross-submissions.
3. All references to Transpower in this document are made in relation to our role as the System Operator.

1.1 Background

4. 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 not yet widespread or frequent, but we are observing them in practice and expect that they will increase in the future.² 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.
5. Currently, the resolution of tie-breaker situations is unprescribed and can require the System Operator to apply its discretion, often 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 less predictable dispatch decisions.

1.2 The proposed solution we consulted on

6. We have decided to adopt the proposed solution we consulted on. The solution introduces a tie-breaker energy constraint within the Scheduling, Pricing and Dispatch (SPD) model. This constraint allocates dispatch at a given pricing node in proportion to offered quantities at the same price, addressing challenges posed by the current unprescribed allocation approach.
7. The solution improves certainty of MW allocation, ensures consistent outcomes from scheduling through to real-time dispatch, and enables all affected participants to better plan and manage their positions.
8. Importantly, the solution does not alter the likelihood of any particular generation type being dispatched off compared to the status quo.
9. Existing practices where System Operator discretion will continue to apply when required.^{3,4}

1.3 Summary of decisions

10. Having considered stakeholder feedback, we have decided to:

1 [Evolving market resource co-ordination: Tie-breaker provisions](#)

2 For example, there is evidence that periods of zero or near zero spot prices are increasing e.g. see [Extreme low prices – the less-scrutinised side of electricity price volatility](#)

3 For example, clause 13.82(2)(a) - [Part 13 - Trading arrangements - 31 July 2025.pdf](#)

4 [Keeping inflexible plant on when dispatched below minimum - overnight](#)

- Implement the proposed tie-breaker solution, which we expect to have completed for it to take effect by 30 June 2026. We will confirm the effective date and remind participants about how the solution will work ahead of putting it into use.

We consider this solution strikes an appropriate balance between certainty, transparency and simplicity. Any future enhancements would complement the solution rather than replace it. The implementation timing reflects the need to follow the formal process for implementing SPD changes.

- Incorporate the tie-breaker solution as a topic for our next Policy Statement review, with consultation scheduled to start in Q1 2026 and the review to be completed by the end of financial year ending June 2026. We consider incorporating the tie-breaker solution into the Policy Statement will support transparency and certainty for participants.

The process we must follow to propose amendments to the Policy Statement for the Electricity Authority (Authority) consideration is set out in the Electricity Industry Participation 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.

- Clarify that the tie-breaker allocations will be pro-rated based on the size of the tied offer price band (not the total offered MW at the node if there are also offers in other price bands).
- Maintain existing processes of applying System Operator discretion when required to prioritise dispatch of the particular generation types needed to maintain power system security. These processes will not be affected by implementation of the tie-breaker solution.
- Acknowledge broader challenges raised during stakeholder engagement.

Engagement with stakeholders since the submission has highlighted several challenges that warrant further exploration in the broader context of the tie-breaker solution. Importantly, we note that many of the proposals raised by stakeholders, particularly those involving generation type differentiation and operational constraints would require broader market design considerations and potential Code amendments.

We have submitted a Code change request to the Authority to enable the use of offer prices to distinguish between generation types.⁵ The intent of the proposal is to automate the current manual decision-making process that typically results in generators with significant operational constraints being retained on the system ahead of intermittent generation. This would be achieved by introducing restrictions on offer prices, allowing the market-clearing process to automatically allocate MW in a manner that complements the proposed tie-breaker solution and enhances certainty, efficiency, and simplicity.

5 CAR180 [Electricity Authority Code amendment register](#)

2 Feedback received

11. Our consultation process provided for a consultation period of 3 weeks from 24 July to 14 August 2025, followed by a one-week period of cross-submissions to 21 August 2025.
12. We received feedback from 9 stakeholder organisations (7 submissions and 2 cross-submissions) representing generator interests and one consultancy agency. The submissions are available on our website.⁶ We appreciate all the feedback we received.
13. We also had subsequent discussions with Ngawha Generation, Eastland Generation and PBA Consulting to work through the issues they raised.

Submissions	Cross-submissions
Helios Energy Genesis Lodestone Energy Mercury Meridian Ngawha Generation PBA Consulting	Contact Energy Eastland Generation

2.1 The System Operator proposed tie-breaker solution

14. Our proposed solution introduces a tie-breaker energy constraint within the SPD model that allocates dispatch at a given pricing node in proportion to offered quantities at the same price. The proposed tie-breaker solution to dispatch in proportion to offers was supported by the majority of submitters that commented on this matter: Contact,⁷ Genesis, Helios, Lodestone, Mercury, and Meridian.
15. Contact, for example, considers that the proposal “gives some certainty to participants ahead of time on how the situation will be managed”. Helios considers that the proposed solution “is equitable, predictable, and objectively manageable.” Lodestone considers that it is a “transparent method that aligns well with nodal pricing principles and reflects international best practice.” Meridian agrees that “the status quo is uncertain ... and can lead to inconsistent and unpredictable dispatch decisions.”
16. The proposal was not supported by Eastland, Ngawha, and PBA Consulting. Eastland and Ngawha are concerned that the option does not take into account the physical operation of generation; with particular reference to geothermal (see discussion below).
17. Eastland, for example submitted that “the System Operator’s preferred tie-breaker solution is not feasible, has costly operational implications for geothermal plant, and an unintended consequence of raising the cost of energy for all New Zealanders.” Ngawha submitted that “no consideration has been given to the physical operation of the generation plant, contribution to grid stability, or the optimal economic solution.”

⁶ [Evolving market resource co-ordination: Tie-breaker provisions](#)

⁷ Subject to “further assessment and consultation before a solution is finalised”.

Transpower response

18. We understand the perspectives of Eastland and Ngāwhā on the operational aspects of generation. However, incorporating generation type or operational constraints into the tie-breaker mechanism would represent a fundamental change to market design and require formal Code amendments. With embedded renewable generation expected to grow (e.g. potential constraints on the transmission lines near Kaikohe this summer)⁸ and generation investors seeking greater clarity, a practical and effective tie-breaker solution is needed now.⁹
19. Following consideration of stakeholder feedback, we have decided to adopt the proposed solution we consulted on. Transpower remains of the view that this solution strikes an appropriate balance between certainty, transparency and simplicity, and helps limit the need for System Operator discretion to be applied.
20. The solution improves certainty of MW allocation where equal-priced offers occur at the same grid injection point under export constraints, ensuring consistent outcomes from scheduling through to real-time dispatch, regardless of generation type.
21. This increased certainty will enable all affected participants to better plan and manage their positions in advance, addressing challenges posed by the current unprescribed allocation approach. Importantly, the proposal does not alter the likelihood of any particular generation type being dispatched off compared to the status quo.
22. The tie-breaker solution preserves existing practices where System Operator discretion is applied.¹⁰ Under clause 84M of the Policy Statement,¹¹ the System Operator may continue to apply discretionary constraints, such as dispatching a generation unit to minimum output to ensure it remains available for peak demand within the unit's restart cycle time. In fact, the improved certainty provided by the tie-breaker solution will give the System Operator greater clarity on whether and when discretion needs to be exercised in real time.
23. Section 2.2 and 2.4 below respond to the matter raised by Eastland and Ngāwhā in more detail.

2.2 Implications of increasing reliance on intermittent fuel

24. Eastland Generation, Genesis and Mercury submitted that further work will be needed as intermittent resources are increasingly used to generate electricity. Genesis submitted that "... it will only provide a partial solution and does not address broader issues with current market design. We therefore support the System Operator (working with the Electricity Authority as needed) considering broader issues with market design to address issues from oversupply of must-run generation".
25. Mercury similarly submitted "further work is required to find a more enduring, long-term solution or solutions to address the increase in the level of variable, renewable, increasingly fragmented generation".

Transpower response

26. Our tie-breaker solution was developed to address these issues. As we noted in the consultation paper the growth of intermittent renewable generation, including generation embedded in distribution networks, increases the likelihood of such situations and we're

8 [Ngawha Generation Limited - Evolving market resource co-ordination Tie-breaker provisions.pdf](#)

9 Section 2.4 [Evolving market resource co-ordination Tie-breaker provisions Consultation Paper.pdf](#)

10 [Keeping inflexible plant on when dispatched below minimum - overnight](#)

11 [Certified policy statement - effective 14 March 2025.pdf](#)

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.¹²

27. As the portion of intermittent generation continues to grow, we expect to identify further areas where changes to system operations rules, tools, processes, and market products are needed. A recent example is the ongoing refinement of dispatching a group of intermittent generators when that group sets the island binding risk. This need became evident during a period of very low prices in spring 2024 and has since been further adjusted in October 2025 based on real-time operational experience, particularly due to differences in curtailment mechanisms used by various wind generators. We will continue to work with the Authority to act in response to the needs of the market and power system in a timely way.

2.3 Potential incentives to over offer

28. Genesis submitted that the System Operator “should ... consider including a provision for preventing participants from over-offering e.g. offering their full nameplate capacity instead of their best view of actual expected volume based on the Forecast of Generation Potential.” Genesis considers that this is “necessary to prevent participants from over-offering to try and gain a larger share of pro-rated dispatch.”
29. PBA Consulting similarly submitted “The most likely pitfall [of the System Operator tie-breaker proposal] is that a dominant generator on a GXP could bid in 48 hours prior with their full 100% output, where realistically we are all aware weather conditions dictate solar and wind output. There is presently no provision to prevent this. With the market operation as existing this then allows a later refinement, where they are aware they already have priority at that GXP.”

Transpower response

30. From 31 July 2025,¹³ the forecast of generation potential (FOGP) has been provided either from centralised intermittent generation forecaster¹⁴ or from an alternative forecast approved by the Authority.¹⁵ This hybrid forecasting arrangement is intended to ensure the accuracy and consistency of the intermittent generation forecasts. Forecasts are required to update every 30 minutes and provide coverage for the following 7 days.
31. The guidance published by the Authority¹⁶ also reinforces that the centralised and alternative forecaster are expected to ensure the root mean square error of their forecasts, half an hour before real time is at or below 10MW. If the actual output is, or is expected to be, more than 10MW above or below the last submitted FOGP value, the intermittent generator should adjust its FOGP under clause 13.9B(2)(a).¹⁷
32. We note that PBA appears to misunderstand the timing and nature of how proportions are determined under the proposed arrangements. Specifically, it seems they believe the proportion is locked in ahead of time, whereas in fact, it is forecast ahead of time and only

12 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, paras 19 & 20.

13 [Improving the accuracy of intermittent generation forecasts | Our projects | Electricity Authority](#)

14 Clause 13.9B (2) - [Electricity Industry Participation Code 2010 - Part 13 Trading arrangements](#)

15 Clause 13.9B (4) - [Electricity Industry Participation Code 2010 - Part 13 Trading arrangements](#) and [Guidance for intermittent generators wanting to use own forecast.pdf](#)

16 [Guidance for intermittent generators on clause 13.822d and clause 13.9B2a.pdf](#)

17 Clause 13.9B(2)(a) - [Part 13 - Trading arrangements - 31 July 2025.pdf](#)

locked in at real-time dispatch. Furthermore, we reiterate that the current intermittent generation offer regime explicitly precludes the type of strategic behaviour PBA has raised as a concern. The design of the regime should significantly limit the potential to deliberately over offer, and ensure forecasts remain accurate, regularly updated, and within defined error tolerances.

2.4 Treatment of different types of generation plant

33. The main area where stakeholder views departed from the consultation proposals was in relation to the treatment of different types of generation, in particular, geothermal plant. Concerns about treatment of different generation were raised by Genesis, Mercury and Ngawha in submission and by Contact Energy and Eastland Generation in cross-submission.
34. Genesis submitted the System Operator should recognise that “different technologies have varying capabilities to respond, which should be factored into dispatch decisions” and should consider “broader issues with market design to address issues from oversupply of must-run generation.” Genesis also submitted that “certain generation types should be prioritized for security reasons, even if this incurs minor reserve cost penalties.”
35. Mercury submitted that “There are ... limitations to a simple application of a solution that allocates dispatch at a given pricing node in proportion to offered quantities. In particular, we note the System Operator will still need to apply discretion where scaling an offer at a node is not feasible, such as in the case of geothermal generation plant.”
36. Ngawha submitted that “Geothermal plants are relatively inflexible generation assets and are designed to operate continuously at consistent generation. Therefore, changing the output frequently or below the minimum operating level is not good industry practice” and that “Other geothermal participants have claimed 13.82 (2)(a) in response to dispatch requests, showing this is an industry-wide issue.”
37. Eastland Generation “strongly supports Ngawha’s submission – that the physical operation of geothermal generation plant means it should not be ‘constrained off’ in a tie breaker event.”
38. Contact similarly submitted that “we support Mercury and Ngawha Generation views that consideration needs to be given to geothermal plant. At present under discretionary dispatch, recognition is given to the merit order position of this type of generation over other renewable generation and the proposal as it stands does not consider this. Typically, geothermal plant is always offered at rated capacity and if forced to reduce output would mean a shutdown and lengthy return to service which has operational implications on the asset owner and the System Operator’s ability to manage security of supply.”
39. Contact proposed that the System Operator consider “a hybrid solution that uses the proposed solution but flags any market nodes where merit order is required to be applied i.e. prioritising different types of generation.” Eastland Generation submitted that “Generation curtailment should occur in the following order: 1. Battery 2. Wind 3. Solar 4. Hydro 5. Geothermal, i.e. curtailed last”.

Transpower’s response

40. We noted in the consultation paper that there can be considerable operational difficulty for generators with relatively inflexible must-run renewable plant like geothermal as well as

thermal plants that require minimum start-up times.¹⁸ While these challenges are acknowledged, we note that the proposals put forward by submitters in this context largely require broader market design considerations and potential Code amendments.

41. The tie-breaker solution is designed to operate within the existing market framework. Generators with secured Must Run Dispatch Auction (MRDA) and embedded generators can offer at \$0/MWh, while others can offer no lower than \$0.01/MWh.¹⁹ This small price difference means that MRDA-backed generation is normally cleared first.
42. Tie-breaker scenarios are most relevant in the scenarios of multiple generators with MRDA (including embedded generators) or none with MRDA are competing at the same price. In these cases (in Table 1), the solution provides a certain and transparent basis for MW allocation, enabling generators to manage their offers under export constraints up to 7 days ahead of real time dispatch.
43. The solution does not alter the likelihood of any particular generation type being dispatched off compared to the status quo.
44. The solution also does not change existing practices where System Operator discretion is applied. However, the improved certainty provided by the tie-breaker solution will give the System Operator greater clarity on whether and when discretion needs to be exercised in real time.

Table 1 Comparison of MW allocation between Current Process and tie-breaker Solution

Scenario (Export Limit=100MW)		Current Process (Status Quo)	With Tie-Breaker Solution
1.MRDA vs no MRDA	G1(MRDA): 60MW@\$0	Not a tie-breaker situation due to price difference. G1 = 60 MW G2 = 40 MW	No change.
	G2(no MRDA): 60MW@\$0.01		
2.All with MRDA	G1&G2: 60MW@\$0	No clear allocation mechanism. Relies on System Operator discretion. G1/G2 MW allocation varies between intervals within the same schedule, and even across successive schedules e.g. 60/40 or 40/60.	Consistent allocation: G1=50 MW G2=50 MW System Operator discretion applies if clause 13.82(2)(a) is invoked.
3.Embedded vs MRDA	G1&G2: 60MW@\$0		
4.All without MRDA	G1&G2: 60MW@\$0.01		
5.Embedded/MRDA vs no MRDA	G1(Embedded): 10MW@\$0	No clear allocation mechanism. Relies on System Operator discretion. G1=10MW G2=40MW G3/G4 MW allocation varies between intervals within the same schedule, and even across successive schedules (e.g. 40/10 or 10/40).	Consistent allocation: G1=10MW G2=40MW G3=25MW G4=25MW System Operator discretion applies if clause 13.82(2)(a) is invoked.
	G2(MRDA): 40MW@\$0		
	G3&G4 (no MRDA): 60MW@\$0.01		

45. We have engaged with several stakeholders, who have raised concerns about how the tie-breaker solution would treat relatively inflexible and must-run renewable plant, and support prioritising different types of generation. In addition, we have identified several other

18 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, para 28.
19 [Guidance for intermittent generators wanting to use own forecast.pdf](#)

challenges that warrant further exploration in the broader context of the proposed tie-breaker solution. These include:

- MRDA scope:

Should MRDA be expanded to account for locational factors, and even prioritisation of certain generation types?

- Embedded generation offers:

With MRDA in place, should embedded generation continue to offer at \$0, given the expected growth of intermittent renewable at the distribution level?

Embedded generators are connected to local distribution networks, where the System Operator currently has limited visibility into how curtailment is managed and whether such curtailment is accurately reflected in market offers. This lack of transparency and potential misalignment could pose potential security risks, including circuit overloading and unintended impacts on dispatch outcomes to other generators, particularly in constrained network scenarios.

- Interaction between MRDA and prioritising different types of generation:

How would MRDA coexist if a tie-breaker solution that prioritises different types of generation (e.g. a geothermal plant offering at \$0.01/MW invoking 13.82(2)(a) vs. intermittent or embedded generators offering at \$0/MW)? This likely results in System Operator discretion being exercised in a manner similar to current practices, where MRDA backed generator sets the risk but is dispatched below its minimum operating level due to high reserve cost.

- Incentives:

If the tie-breaker solution favours certain generation types, will those generators still have incentives to secure MRDA?

- Negative pricing²⁰:

Could negative pricing, which allows generators to reflect shutdown cost in their offers, provide a more effective solution along with the tie-breaker solution?

46. We have submitted a Code change request²¹ to the Authority to enable the use of offer prices to distinguish between generation types. This would be achieved by introducing restrictions on offer prices, allowing the market-clearing process to automatically allocate MW in a manner that complements the proposed tie-breaker solution.
47. This approach avoids the need for changes to MRDA or broader market design and could be implemented with minimal cost. It directly addresses the challenges identified through stakeholder engagement, while preserving the role of the tie-breaker solution in scenarios where curtailment decisions must be made between generators of the same type. In this way, the Code change proposal would complement, rather than replace, the tie-breaker mechanism, supporting greater certainty, efficiency, and simplicity in scheduling and dispatch outcomes.

20 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, paras 26 & 53.
21 CAR180 [Electricity Authority Code amendment register](#)

2.5 Alternative options

48. There were no alternative options raised in submissions that were not included in the consultation.

2.6 Meridian's proposed refinements

49. Meridian proposed two refinements to the System Operator tie-breaker proposal. They suggested that "The System Operator should specify that tie-breaker allocations will be pro-rated based on the size of the tied offer price band (not the total offered MW at the node if there are also offers in other price bands). The intended outcome was not clear from the consultation document."
50. Meridian also emphasised the importance that "for intermittent generators the tie-breaker allocation should be pro-rated based on offered MW at the tied offer price as limited by the forecast of generation potential." Meridian is of the view that this will "ensure that there is no unintended curtailing of low-cost generation under the proposed approach."

Transpower response

51. We appreciate Meridian's submission and confirm that both clarifications align with our intentions. Meridian's worked example accurately demonstrates that tie-breaker allocations will be pro-rated based on offered MW at the tied offer price, limited by the FOGP for intermittent generation, provided the total quantity offered into a single tranche.
52. Using the same example, under a 160MW export limit,
- G1 (an intermittent generator) offers 100 MW at \$0.01 with a FOGP of 10MW
 - G2 offers 300MW at \$0.01
 - The tie-breaker solution allocates 5.2MW to G1 and 154.8MW to G2 in forecast schedules.

Export Limit	160MW			Tie-breaking \$0.01 offer block
	Offer			Cleared (schedule)
	\$0.01			
G1 (MW)	100	FOGP = 10		5.2MW@\$0.01 [160x(10/310)]
G2 (MW)	300			154.8MW@\$0.01 [160x(300/310)]

53. To illustrate how outcomes may vary in real time dispatch, we extend the example below. These simplified examples focus on differences arising from intermittent generation forecast accuracy. Other factors, e.g. load forecast accuracy, may also affect dispatch outcomes.
54. To maximise the use of intermittent generation resources, real time dispatch uses the latest intermittent generation offers, replacing FOGP with the current output value from SCADA²² when the generator is not constrained for price or security reasons. This means the tie-breaker solution allocates MW based on the generator's actual output at the time of dispatch. As a result, discrepancies may arise between forecast and real time dispatch outcomes. These discrepancies are not caused by the tie-breaker solution itself, but rather by the different inputs used in each scheduling process, specifically the use of half-hour forecast values (FOGP) in forecast schedules vs five-minute actual generation values in real-time dispatch.

22 [GL-OC-209 SPD Schedule Inputs](#)

55. Outcome 1: G1's actual generation > FOGP

- G1 offers 100 MW at \$0.01 with a FOGP of 10MW but actual output of 20MW
- G2 offers 300MW at \$0.01
- The tie-breaker solution allocates 10 MW to G1 and 150 MW to G2 in real time dispatch.

Export Limit	160MW			Tie-breaking \$0.01 offer block
	Offer			Cleared (dispatch)
	\$0.01			
G1 (MW)	100	Actual = 20		10MW@\$0.01 [160x(20/320)]
G2 (MW)	300			150MW@\$0.01 [160x(300/320)]

56. If G2 can not comply with the dispatch instruction due to ramp down limitations and invokes clause 13.82(2)(a), the System Operator may apply a discretionary constraint to keep G2 at its minimum operating level (e.g. 154.8MW). The solution can then back off G1 without violating the export limit.

57. Outcome 2: G1's actual generation < FOGP

- G1 offers 100 MW at \$0.01 with a FOGP of 10MW but actual output of 5MW
- G2 offers 300MW at \$0.01
- The tie-breaker solution allocates 2.6MW to G1 and 157.4MW to G2 in real time dispatch.

Export Limit	160MW			Tie-breaking \$0.01 offer block
	Offer			Cleared (dispatch)
	\$0.01			
G1 (MW)	100	Actual = 5		2.6MW@\$0.01 [160x(5/305)]
G2 (MW)	300			157.4MW@\$0.01 [160x(300/305)]

58. To support understanding how the solution may operate in practice, we have provided additional worked examples covering a range of scenarios. The tie-breaker solution applies at the tied offer price, which may occur at both low and high price tranches.

59. Example 1: Low Price Tie with a 70MW export limit,

- G1 offers 40MW at \$0
- G2 offers 60MW at \$0
- The tie-breaker solution allocates MW proportionally to each generator's share of the \$0 block, resulting in 28MW to G1 and 42MW to G2.
- The marginal price at the grid injection point could be zero.

Export Limit	70MW			Tie-breaking \$0 offer block
	Offer			Cleared
	\$0	\$10	\$100	
G1 (MW)	40	10		28MW@\$0 [70x(40/100)]
G2 (MW)	60		40	42MW@\$0 [70x(60/100)]

60. Example 2: High Price Tie with a 70MW export limit:

- G1 offers 20MW at \$0 and 30MW at \$100.
- G2 offers 10MW at \$10 and 90MW at \$100.

- If the marginal price is above \$100, the tie-breaker solution pro-rates within the \$100 block, allocating 10MW to G1 and 30MW to G2.
- Including the lower priced allocations, the total scheduled quantity is 30MW for G1 and 40MW for G2.

Export Limit	70MW			Tie-breaking \$100 offer block
	Offer			Cleared (Marginal \$100+)
	\$0	\$10	\$100	
G1 (MW)	20		30	30MW (20@\$0 + 10@\$100) [10@\$100 = 40x(30/120)]
G2 (MW)		10	90	40MW(10@\$10 + 30@\$100) [30@\$100 = 40x(90/120)]

2.7 Negative pricing

61. Genesis submitted that it supports the System Operator and the Authority exploring negative pricing “as is used in other comparable jurisdictions such as the Australian National Electricity Market and as suggested by MDAG.” We note that the Authority has announced it will investigate negative pricing as part of its MDAG reforms (MDAG recommendation 29).²³
62. Meridian noted “the System Operator’s views on negative spot pricing” but made no comment beyond that it “agree[s] with the System Operator that even with negative spot pricing there would still be a need for a tie-breaker solution, albeit less often.”

Transpower response

63. Transpower supports adoption of negative pricing and will assist the Authority on this matter as needed. As we noted in the consultation introducing negative price offers to the market design could support more granular price differentiation, particularly across different types of generators and we would expect this to reduce the frequency of tie-breaker scenarios occurring. 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.²⁴
64. Also as we noted in the consultation paper, we think that 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.²⁵

2.8 Qualitative cost benefit analysis

65. Of the stakeholders that commented on the qualitative cost benefit analysis (CBA), it was generally agreed that it is appropriate to rely on qualitative evaluation (Helios, Lodestone, Ngawha, and PBA Consulting) and the benefits of the proposal can reasonably be expected to outweigh costs (Helios, Lodestone, and Meridian).
66. Helios, for example, submitted that “... the benefits are difficult to quantify, particularly those related to reducing operational challenges caused by random outcomes and addressing inequities between generators.” Lodestone submitted that “Given the limited frequency and scope of tie-breaker situations, a qualitative approach seems appropriate” and that “the

23 https://www.ea.govt.nz/documents/7762/MDAG_programme_dashboard.pdf

24 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, para 26.

25 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, para 53.

qualitative benefits-greater investor confidence, operational certainty, reduced discretionary intervention, and equity among market participants - outweigh the relatively minor implementation costs."

67. Meridian submitted: "there are likely to be material benefits 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. Meridian expects those benefits to outweigh any implementation costs for the System Operator (and many of the costs may already have been incurred in development and testing of a prototype). We do not expect costs to any other party as a result of the proposal."
68. Ngawha agrees that a solution would be beneficial but doesn't consider enough work has been done to define the costs and benefits.

Transpower response

69. Transpower welcomes this feedback. We continue to believe that qualitative CBA is appropriate and that it can be reasonably expected the benefits of the proposal will outweigh the costs. We note in particular that "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" and "The preferred option has proven successful in other jurisdictions and we have tested a prototype solution successfully."²⁶

2.9 Next steps: Progression of a proposal to incorporate a tie-breaker solution into the Policy Statement

70. The stakeholders that submitted on this point (Contact, Helios, Genesis, Lodestone, Meridian and PBA Consulting) supported Transpower progressing a proposal to incorporate any tie-breaker solution into the Policy Statement.
71. Contact, for example, submitted that "the final agreed solution should be adopted in the Policy Statement for transparency." Genesis similarly submitted that "Providing transparency around the tie-breaker approach is beneficial and will enhance market certainty." Lodestone submitted that "Clear policy direction will also help prevent ad hoc or discretionary practices from being introduced over time." Meridian submitted that "Inclusion in the Policy Statement would be consistent with clause 8.11 of the Code."
72. Ngawha submitted that further consultation is needed.

Transpower's response

73. We are going to implement the proposed tie-breaker solution, which we expect to have completed for it to take effect by 30 June 2026. We will confirm the effective date and remind participants about how the solution will work ahead of putting it into use.
74. We have decided to consider incorporating tie-breaker situations into the Policy Statement through our next review, which we plan to progress during the financial year ending June 2026. We think doing so would support greater transparency and certainty for market participants.²⁷ This process will include consultation on draft proposed Policy Statement amendments ahead of any final amendment proposal being submitted to the Authority for its consideration.

26 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, para 62.

27 Transpower, [Evolving market resource coordination: Tie-breaker provisions Consultation Document](#), 24 July 2025, para 63.

75. The process we must follow to propose amendments to the Policy Statement to the Authority for its consideration is set out in the Electricity Industry Participation 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.
76. We have submitted a Code change request to the Authority to enable the use of offer prices to distinguish between generation types.²⁸ This change would complement the proposed tie-breaker solution and support more efficient and transparent MW allocation, particularly in scenarios involving operationally constrained generation.

28 CAR180 [Electricity Authority Code amendment register](#)