

Instantaneous reserve cost allocation to groups of generating units

Decision paper

22 October 2025

Executive summary

The Electricity Authority Te Mana Hiko (Authority) has decided to amend the Electricity Industry Participation Code 2010 (Code) to update the way instantaneous reserve costs are allocated.

Electricity supply and demand must always be in balance to maintain quality of supply to consumers. The System Operator procures instantaneous reserve (reserve) to manage potential events that could cause the supply-demand balance to be disrupted such as the sudden loss of a significant generator or transmission circuit.

For efficiency, the costs of procuring reserve should be allocated to the party best able to manage them. This means that the party causing the need for reserve should pay costs in proportion to the risk their assets present to system stability.

As generation technology has evolved, the cost allocation methodology for reserve in the Code has not kept pace. This has resulted in an increasing number of potential event causers not having to pay their share of the cost of procuring reserve, eg, solar and wind farms. This potentially:

- increases the costs for other potential event causers
- reduces incentives for parties to actively reduce the risks their assets present to the system
- does not support a level playing field between different types of generation technologies and configurations.

The Authority wants to incentivise efficient investment for the benefit of consumers

The Authority has decided to amend the Code so that more potential event causers pay an appropriate share of the reserve procurement costs related to their assets.

We have decided to update the reserve cost allocation methodology in order to:

- create a more level playing field for different types of technologies and asset configurations to promote competition and efficient investment in future generation
- incentivise investments that reduce system risk and increase power system stability and resilience
- reduce costs by reducing the need to procure reserve and the resulting costs that are passed on to consumers in the long run.

Next steps

The Code amendment will come into force on 1 October 2026. This will allow time for the System Operator to update the methodology in its cost allocation tool and arrange the necessary data supply from participants.

From 1 October 2026, the System Operator will publish and maintain a list of all at-risk generation with a total generating capacity of more than 60MW in accordance with the new clause 8.59A of the Code. It will also update the policy statement to include information about how it creates and updates the list of at-risk generation. The System Operator must consult on any changes to the Policy Statement.

From 1 October 2026, participants will receive reserve cost allocations based on the new methodology in the Code.

Contents

Executive summary	2
1. Purpose	4
2. Context for the Authority's decisions	4
The System Operator procures reserve to maintain quality of supply to consumers	4
Reserve costs are allocated on a causer pays basis to incentivise actions that increase reliability and reduce costs	5
Changes to reserve cost allocation are required to keep up with the changing generation mix	5
The Authority wants to incentivise efficient investment for the benefit of consumers	6
3. Decisions and responses to submissions	7
Most submitters agreed with our proposal	7
Submitters consider the cost allocation should account for reliability and probability of failure	8
Submitters raised issues regarding the efficiency and fairness of the cost allocation methodology	9
Submitters proposed changes to the drafting of the Code amendment	11
Out of scope considerations	13
4. The amendment will promote competition, reliability and efficiency for the long-term benefit of consumers	13
5. Next steps	14
6. Attachments	14
Appendix A Approved Code amendment	15

1. Purpose

- 1.1. The purpose of this paper is to convey the Authority's decision to update instantaneous reserve (reserve) cost allocation to include groups of generating units in the Electricity Industry Participation Code 2010 (Code).
- 1.2. This decision paper follows our July-August 2024 consultation and explains:
 - a) our decisions and responses based on feedback received from industry participants
 - b) next steps for implementation.

2. Context for the Authority's decisions

The System Operator procures reserve to maintain quality of supply to consumers

- 2.1. The System Operator procures reserve to protect consumers from the risk of a sudden event that could disrupt electricity supply. The System Operator determines likely risks to the system and classifies these events as 'contingent events' (CEs) or 'extended contingent events' (ECEs).

What is instantaneous reserve?

Instantaneous reserve (reserve) is the generation capacity or demand reduction that is available to quickly respond to an unexpected event. An unexpected event could include the sudden loss of a significant generator or transmission circuit. These events can cause a large drop in system frequency, which, if not addressed quickly, could lead to wider disruption to supply.

Instantaneous reserve can be provided by generators (generator reserve) or by automatically disconnecting demand (interruptible load).

- 2.2. A CE is typically the sudden loss of a single generating unit or a single pole of the HVDC. An ECE is a rare event¹ and is typically the sudden loss of the HVDC bipole or multiple generating units.²
- 2.3. The System Operator procures enough reserve to cover the largest of these events. This process ensures there is enough reserve to cover any single event of that size or smaller.

¹ The most recent bipole trip with a significant frequency impact occurred in 2013 during the commissioning of HVDC Pole 3. Multiple generator trips are typically busbar faults, which on average occur less than once every 50 years.

² The System Operator also relies on automatic under-frequency load shedding to recover system frequency following an ECE. The System Operator's Policy Statement defines CEs and ECEs and how they are managed.

Reserve costs are allocated on a causer pays basis to incentivise actions that increase reliability and reduce costs

- 2.4. The cost incurred by the System Operator in procuring reserve is known as the 'availability cost'. It is calculated for each trading period in each island for each month.
- 2.5. Availability costs are allocated based on a causer pays principle. Causer pays methodologies incentivise parties that cause the costs to take actions to reduce those costs where they can. Availability costs should be allocated proportionally to participants whose generation or transmission is considered a CE risk. This is determined by how much reserve is needed to cover the potential loss of injection resulting from the CE.
- 2.6. The current methodology allocates costs for each trading period to generators and the HVDC owner. The allocations to generators are based on their injections from individual generating units above 60MW.³ The allocations to the HVDC owner are based on the HVDC transfer above 60MW that would be lost.⁴
- 2.7. This means that the availability cost is allocated to most parties that are 'potential causers' of a CE based on the relative risk they pose to the electricity system.
- 2.8. The cost allocation methodology is intended to reduce costs and promote reliability:
 - a) The methodology incentivises participants to invest in a greater number of small generating units, rather than fewer large units to achieve the same generating capacity. This is because they would receive a lower total allocation of reserve costs.
 - b) Having larger numbers of smaller generating units should provide increased resilience as a single failure will have less impact on the power system.
 - c) Investment in lower risk generation plants can mean less reserve needs to be procured. Procurement of less reserve helps reduce the overall costs of supplying electricity to consumers over the working life of the units. This incentive would be balanced against the relative cost of buying, installing and maintaining two smaller units.

Changes to reserve cost allocation are required to keep up with the changing generation mix

- 2.9. Over time, the intent and practical application of reserve cost allocation have become misaligned.
- 2.10. Increasingly, groups of generating units like wind and solar farms are connecting to the grid as many small units behind a single point of connection. The System Operator has started to treat these groups as CE risks due to the single point of failure and the potential risk they present to the system. The System Operator currently classifies six wind, two geothermal, and two thermal generating stations as groups of generating units posing CE risks:

³ It is considered the sudden loss of 60MW, or less, poses no risk to consumer supply as the power system is resilient enough to accommodate it.

⁴ The HVDC link has two 'poles' to transfer electricity between islands. If one pole trips off the system, the other pole can ramp up to provide some 'self-cover', reducing the total transfer lost.

Station (group of units)	GIP	Type
Junction Road	JRD1101 JRD0	Thermal
Turitea	LTN2201 TUR0	Wind
McKee	MKE1101 MKE1	Thermal
Nga Tamariki	NAP2202 NTM0	Geothermal
Tararua Central	TWC2201 TWF0	Wind
Te Apiti	WDV1101 TAP0	Wind
Mokai	WKM2201 MOK0	Geothermal
Waipipi	WVY1101 WPP0	Wind
West Wind A	WWD1102 WWD0	Wind
West Wind B	WWD1103 WWD0	Wind

- 2.11. However, none of these stations receive any allocation of reserve costs. This is because cost allocations are made *per generating unit* rather than at a group level, and these stations do not include any single unit with capacity above 60MW. Windfarms, for example, typically have generation units (single turbines) of less than 5MW.
- 2.12. This is a problem because:
- the cost of procuring reserve does not properly follow the principle of ‘causer pays’
 - plant owners who do not receive an allocation of reserve costs but whose asset contributes to risk do not factor reserve allocation costs into their investment, reducing the efficiency of investment decisions
 - it could lead to the System Operator procuring more reserve due to inappropriate incentives
 - not allocating reserve costs to some potential event causers increases the costs for others, and can lead to higher costs for consumers in the long run because it will not promote efficient decisions about what generation technologies to invest in.
- 2.13. If not resolved, we expect this problem will worsen as the proportion of intermittent generation (like wind and solar) increases in the mix. Transpower’s connection stages data indicates that around 79% of generation projects in the delivery stage are intermittent generation. Over 50% of projects in the application and investigation stages are solar or onshore wind.⁵

The Authority wants to incentivise efficient investment for the benefit of consumers

- 2.14. We have decided to update the reserve cost allocation methodology in order to:
- create a more level playing field for different types of technologies and asset configurations to promote competition and efficient investment in future generation
 - incentivise investments that reduce system risk and increase power system stability and resilience

⁵ These stages correspond to the first five stages of Transpower’s customer journey stages shown here: [Our grid connection process](#) | [Transpower](#)

- c) reduce costs by reducing the need to procure reserve and the resulting costs that are passed on to consumers in the long run

3. Decisions and responses to submissions

- 3.1. On 22 July 2024, we published a consultation paper *Instantaneous reserve cost allocation to groups of generating units*. The consultation period closed on 23 August 2024 and cross submissions closed on 30 August.
- 3.2. We received eight submissions and one cross submission in response to our consultation paper and have published these on our website.⁶
- 3.3. We did not proceed with a decision last year, as our priorities pivoted toward Energy Competition Task Force initiatives.
- 3.4. The Authority has now analysed submissions and has decided to change the Code so that, for the purpose of allocating reserve costs, groups of generating units are treated the same as single generating units if they present the same risk. This means allocations will be based on injections above 60MW from generation that is either:
 - a) a single generation/generating unit
 - b) groups of generation/generating units comprising a single risk, as determined by the System Operator
 - c) the CE risk presented by the High Voltage Direct Current (HVDC) link.
- 3.5. We have also decided to change the Code amendment to reflect feedback from submitters and more accurately reflect the intent of our proposal.
- 3.6. The change will come into effect on 1 October 2026.

Most submitters agreed with our proposal

- 3.7. Our final proposal is very similar to the proposal we consulted on. We proposed to change the Code to ensure that groups of generating units whose assets cause the need for instantaneous reserves pay an appropriate share of the procurement costs.
- 3.8. Most submitters agreed with the description of the issues, the objectives of the proposal and the need for change.
- 3.9. This section summarises the Authority's decisions and feedback we received on our proposal. Feedback mainly related to the themes of:
 - a) how reliability and probability of failure are determined
 - b) the efficiency and fairness of various aspects of the proposed cost allocation methodology
 - c) suggested improvements to the drafting of the Code amendment

⁶ [Instantaneous reserve cost allocation to groups of generating units](#) | [Our consultations](#) | [Our projects](#) | [Electricity Authority](#)

Submitters consider the cost allocation should account for reliability and probability of failure

- 3.10. Contact suggested reliability and probability of failure should be assessed on a case-by-case basis rather than by broad based technology assumptions and included in the way reserve costs are allocated under the Code.
- 3.11. Nova submitted that the allocation methodology should consider the probabilities of generation being lost from the system. In particular, it suggested that wind and solar farms connected to the grid via a single transformer should receive a lower allocation than a single large generating unit. Nova submitted this should be the case because wind and solar farms pose a lower risk of failure and loss to the system.
- 3.12. In Nova's view, wind and solar farms connected with a single transformer should be considered an ECE and be allocated costs according to an ECE assessment. Nova considered that the event charge⁷ would be enough to incentivise efficient investment in connection assets. Nova also noted that the event charge could be increased to improve this incentive.
- 3.13. Contact asked if a Code change was needed to enable the System Operator to accurately determine how much output an intermittent generator is producing. This would also affect how much reserve needs to be procured for that generator.

Authority response

- 3.14. The Authority considers it appropriate to allocate instantaneous reserve costs to all CE risks based on the size of the largest risk. This is because reserve is procured to cover all potential CE risks.
- 3.15. The System Operator accounts for the probability of asset failure when defining what constitutes a CE or ECE. This is done as part of the Credible Event Review (CER) process, which involves consultation with industry. Participants and consumers have the opportunity through the System Operator's consultation process to put forward their views about what should classify as a CE or ECE.
- 3.16. The reserve cost allocation method we will implement as a result of this decision will incentivise prospective generation investors to avoid being classified as a CE. They can do this by building more reliable plant, where it is economic to do so. The event charge will also incentivise investors to build more reliable plant. This is because generators and the grid owner are required to pay the event charge every time the loss of their plant causes an underfrequency event.
- 3.17. The probability of asset failure is considered in the event charge. This categorisation is also part of the System Operator's CER process.
- 3.18. We think it is appropriate that cost allocation aligns with classification of CEs, because this is what determines reserve requirements. Different CEs of the same size will have different probabilities of tripping but will still require the same reserve cover. We encourage participants to raise their concerns about what should constitute a CE as part of the periodic CER process.

⁷ When an event occurs on the system, there is a charge to the causer of the event (either a generator or the grid owner). The event charge incentivises investment in reliable plant.

Submitters raised issues regarding the efficiency and fairness of the cost allocation methodology

- 3.19. Nova, Meridian and Genesis provided feedback on the efficiency and fairness of various aspects of our proposal.

Meridian considers the grid owner has insufficient incentives to reduce costs

- 3.20. Meridian submitted that the grid owner faces little or no incentive to avoid the costs related to transfer of electricity across the HVDC. It suggested that this is because it can pass these costs onto consumers.

Authority response

- 3.21. The grid owner can act in ways that reduce costs related to the transfer of electricity across the HVDC in two main ways:
- a) **Efficient investment** – The grid owner is incentivised to account for all costs and benefits when making major investment decisions. This is because the Commerce Commission reviews the grid owner's proposed major capital expenditure and requires it to pass an economic test. The grid owner also asks the public for input on these decisions and how costs are shared among grid customers.
 - b) **Efficient operation** – The grid owner is able to reduce the size of the CE risk it causes by altering the operational settings of the HVDC. An example in practice was in 2016, when the grid owner adjusted HVDC transfer settings to provide greater self-cover. This benefitted consumers by reducing the cost of transferring electricity on the HVDC. This behaviour suggests that the grid owner has at least some incentive to reduce costs for consumers.

Nova considers it inefficient to incentivise risk reduction in non-core grid connections

- 3.22. The security requirement for the core grid is N-1.⁸ Nova noted that in some cases, generation connects to the core grid via a single non-core grid line. In their view, if there is not N-1 redundancy in grid assets on the non-core grid, then building redundancy in connection assets between the generation and point of connection to the grid (for example adding another short connection line) would place a largely pointless investment burden on the generator group.

Authority response

- 3.23. The Authority determines, under part 12 of the Code, what is core grid and what is not. The grid reliability standards require core-grid to achieve N-1 security status.
- 3.24. However, it is up to the System Operator, in consultation with industry, to determine whether or not the generation is considered a CE. For example, the length of the connection line might influence that decision.
- 3.25. The Authority agrees that in the example provided by Nova, requiring a party to pay reserve costs may not always lead to efficient investment incentives.

⁸ N-1 means that the system must be able to withstand the failure of any one major component without interrupting power supply or violating operational limits. "N" stands for the total number of critical system elements (like generators or transmission lines).

- 3.26. However, creating efficient investment incentives is not the sole motivator of the causer pays methodology. It is also important to create a level playing field for different types of generation. This means risk causers pay a share based on the CE risk they pose.
- 3.27. The grid owner does not currently pay when the non-core grid has 'N' security level during normal operating conditions. The Authority considers that if neither the grid owner nor the generator paid a share of reserve costs in these situations, there would be no incentive to ensure efficient levels of risk. This is why generators are made liable for a share of instantaneous reserve costs.
- 3.28. Similarly, a distributor would not be required to pay a share of reserve costs if it causes a CE risk due to only having 'N' security on its interconnection assets during normal operating conditions.
- 3.29. We may consider an enhancement at some time in the future where the grid owner and distributors also pay a share of reserve costs for these risks. Any change would be subject to consultation.

Genesis raised the need to exclude recent and upcoming investment decisions from receiving an allocation

- 3.30. Genesis considered that a fair transition means that the new methodology should not apply to investment decisions or asset purchases made within 24 months prior to the change.

Authority response

- 3.31. The Authority does not see recent investment decisions as being less deserving of cost allocation compared to, for example, more established wind farms. In both cases, the investment decision was made before we decided to make this change. Applying these costs to recent investment and current generation could still provide useful price signals. It could incentivise investment in flexible assets that can provide reserve to offset reserve costs (as part of a generation portfolio). It could also incentivise building additional redundancy in connection assets.
- 3.32. Exposing all applicable generation to these costs will also ensure that reserve costs can play an appropriate part in any decommissioning decisions. If costs are not appropriately shared, decommissioning incentives might be distorted.
- 3.33. Participants should factor into their decision-making the costs that their investments cause.

Nova considers that costs should be allocated on a beneficiary pays basis

- 3.34. Nova submitted that the Authority's causer pays methodology for reserve cost allocation is inequitably biased against the supply side. Nova stated, if the beneficiary pays principle of the Transmission Pricing Methodology (TPM) was applied to reserve cost allocation, then the demand-side should also pay an appropriate equitable share.

Authority response

- 3.35. Consumers ultimately bear the cost of having electricity supplied to where they need it.

- 3.36. Where practical, the Authority generally prefers a causer pays method over a beneficiary pays method for allocating cost. This is because causer pays methodologies incentivise parties that cause the costs to take actions that reduce those costs.
- 3.37. For example, with our decision, wind and solar farm owners will be incentivised to build redundancy in their connection assets if it is economic to do so. This may reduce reserve procurement costs because reserve is only required to cover wind and solar farms with a single point of failure.
- 3.38. While consumers benefit from reserve procurement, their actions do not impact reserve procurement. Allocating a portion of the costs to consumers would dampen the incentives on generators and the HVDC owner, whose actions can and do impact reserve procurement costs.
- 3.39. The TPM includes a mixture of methods that balance economic efficiency with implementation practicalities. The costs of building connection assets, for example, are allocated using a causer pays method where costs are recovered directly from the connecting parties. Interconnection assets are recovered under the TPM using a beneficiary pays method because a causer pays method would be impractical.

Submitters proposed changes to the drafting of the Code amendment

- 3.40. Meridian and Transpower suggested changes to improve the drafting of the Code amendment.

Submitters suggested clarifications regarding System Operator requests for information

- 3.41. Meridian suggested two changes to the proposed new clause 8.59A to improve clarity on the scope of System Operator requests. They suggested to:
- update clause 8.59A(5) to state that *"the System Operator may request from any participant information about electricity injected by 'at risk generation', where that information is required to calculate allocations of availability costs under clause 8.59 for that 'at risk generation'."*
 - add an additional subclause after clause 8.59A(5) which states that, *"where the System Operator already holds the relevant electricity injection information (e.g. from SCADA data), they may, by agreement with the relevant participant, use this information rather than making an additional request to the participant."*
- 3.42. Transpower proposed a wording change to 8.59A(5) to limit the information requested to points of connection with single units >60MW and to groups of generating units >60MW as follows:
- 8.59A(5) The System Operator may:
- request from the participant responsible for at risk generation information about the generation from a generation unit (>60MW) or group of generating units (>60MW) and
 - acting reasonably specify the time frame to provide the information, its format, and the method of delivery.

Authority response

- 3.43. We consider Meridian and Transpower's suggestions to be sensible and non-controversial changes.
- 3.44. We have decided to amend clause 8.59(A) to reflect the feedback received, as set out in Appendix A.

Transpower suggested drafting changes to clarify the way that contingent risks connect to the grid

- 3.45. Transpower proposed we unbold the term 'connection asset' and replace 'grid' with 'network' in clause 8.59A. Transpower reasoned that these changes would ensure the amendment captured connection assets owned by the generator rather than the grid owner, as well as generation connected to a distribution network. For example, Transpower noted a windfarm may be on a dedicated distributor owned feeder, which exists solely to connect the generation to the grid.
- 3.46. Transpower also proposed replacing the reference to '*single GIP*' with '*single point of connection*' to cover contingent risk that connects to a Grid Exit Point (GXP) and not a Grid Injection Point (GIP).

Authority response

- 3.47. Our intent is to charge all groups of generating units at a single point of connection when the system categorises such a group as a single CE and where the owner of those units caused the CE risk.
- 3.48. In principle, the changes should therefore include all situations where the CE risk relates to assets used for connecting the generation to distribution networks or to the grid. This is because generators can be considered causers of these risks, for the following reasons:
- a) If they own the assets: The level of redundancy was the generator's choice alone
 - b) If the assets are owned by the grid owner: Under the Code, the connecting party, whether the generator or the distributor, is able to negotiate with the grid owner the level of redundancy in these assets.
 - c) If the assets are owned by a distributor, either for connecting the generation to the grid or the distribution network: While there are no specific Code provisions for doing so, we expect generators will be able to negotiate redundancy levels with distributors. If they are unable, they will either have the choice to build their own assets, or to not connect their generation at that location.
- 3.49. We therefore agree with the intent of the Transpower's suggestions. We have improved the drafting to clarify that connection assets include any assets used for the sole purpose of connecting to a distribution network or to the transmission grid, whether directly or indirectly (see Appendix A for the updated drafting).
- 3.50. Our proposed use of the term GIP was intended to capture situations where the generation was indirectly connected to a GXP, i.e. through a distribution network. We used the term GIP because points of connection to the grid are considered GIPs under the Code for the purposes of market trading and settlement. In our

proposed amendment, we decided not to use the term point of connection in place of GIP because we thought it may not have been clear that this included generation indirectly connected to the grid.

- 3.51. However, having considered Transpower's submission, we have decided to replace GIP with '*point of connection to the grid in respect of which the generator is required to submit an offer*'. We consider that this drafting reflects the policy intent and avoids confusion.

Out of scope considerations

- 3.52. As noted in our consultation paper we are focused on the immediate issues to ensure participants receive early clarity and a timely change to their likely reserve cost allocation.
- 3.53. Some submitters provided feedback that was out of scope. Any further work to enhance the cost allocation methodology, or the event charge, will be considered as part of our on-going work plan.

4. The amendment will promote competition, reliability and efficiency for the long-term benefit of consumers

- 4.1. The Authority's main objective, as outlined in section 15(1) of the Act, is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- 4.2. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The additional objective applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers.
- 4.3. This amendment does not concern dealings between participants and these consumers; thus, the additional objective does not apply. Even so, the Authority considers that the amendment is consistent with this objective and will provide long term benefits to these consumers through the promotion of the matters in the main objective (competition, reliability, and efficiency).
- 4.4. Section 32(1) of the Act states that the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

The amendment complies with section 32(1) of the Act

- 4.5. The Authority considers the Code amendment to be consistent with the Authority's statutory objectives under section 15 of the Act and that it complies with sections 32(1)(a), (b) and (c) of the Act.
- 4.6. The Code amendment promotes all three limbs of the Authority's main statutory objective as follows:
- a) **competition** between different technologies and asset configurations will be improved by removing the advantages afforded to some technologies. This will

lead to more efficient generation investment and decommissioning decisions and therefore lower costs for consumers in the long term

- b) **reliability** will be improved by incentivising more of the potential causers of procurement to act to reduce the size of system risks
- c) **efficient operation** will be improved by incentivising actions that reduce the need for procuring reserve or encourage the causers of reserve costs to offer more reserve to offset their allocation of costs.

The benefits of the amendment are greater than the costs

- 4.7. The Authority considers that the benefits of these changes will outweigh the associated costs as described in the consultation paper.
- 4.8. The costs to implement this proposal include approximately \$175,000 for updating the System Operator's and Clearing Manager's tools and processes. Given the relatively low costs to implement the proposal, the Authority considers that the benefits of this proposal outweigh the costs.
- 4.9. Transpower considers that targeting the changes to only at-risk generation under normal conditions at a single point of connection will achieve the benefits with minimal disruption to its tools and processes.
- 4.10. Transpower also supports the efficiency of the proposals, noting it agrees with the Authority's proposal to enable the System Operator to update its classification of a contingent event without the need for Code change.
- 4.11. All submitters agreed the Authority's proposal complies with s32(1) of the Electricity Industry Act 2010 and we consider our final amendment also achieves this.

5. Next steps

- 5.1. The Code amendment (Appendix A) will come into force on 1 October 2026.
- 5.2. This will allow sufficient time for the System Operator to implement the necessary changes in its ancillary services cost allocation tool.
- 5.3. From 1 October 2026 the System Operator will publish and maintain a list of all at-risk generation with a total generating capacity of more than 60MW in accordance with the new clause 8.59A of the Code. It will update the Policy Statement to include information about how it generates and updates the list of at-risk generation. The System Operator must consult on any changes to the Policy Statement.
- 5.4. From 1 October 2026, participants will receive reserve cost allocations based on the new methodology in the Code.

6. Attachments

- 6.1. The following appendices are attached to this paper:

Appendix A Approved Code amendment

Appendix A Approved Code amendment

Red text shows Code changes

Highlighted text shows drafting changes made following consultation.

1.1 Interpretation

[...]

at-risk generation means a generating unit or group of generating units as identified in the list of at-risk generation maintained by the system operator in accordance with clause 8.59A

[...]

connection asset,

(a) for the purposes of Part 8, and subparts 2, 6 and 7 of Part 12, has the meaning set out in the transmission pricing methodology; and

(b) for the purpose of Part 8 also means assets that are used for the sole purpose of connecting generation—

(i) to the grid via a distribution network; or

(ii) to a distribution network

[...]

8.59 Availability costs allocated to generators and HVDC owner

The availability costs in a billing period must be allocated separately to persons in the North Island and South Island in accordance with the following formula:

$$\text{Share}_t = \text{Ac}_t * m_t \frac{\quad}{M_t}$$

where

Share_t is the **availability cost** allocated to a **generator** who owns at-risk generation generating unit x or to the **HVDC link** for **trading period** t for the North Island or South Island as appropriate

Ac_t is the **availability cost** for the North Island or South Island as appropriate incurred in respect of **trading period** t

m_t $\left\{ \begin{array}{l} \text{is } \max(0, \text{INJ}_{\text{GEN}t} - (h * \text{INJ}_D) - E^{\text{IR}}_{\text{GEN}t}) = m_{xt} \text{ for any } \text{at-risk} \\ \text{generation generating unit} \\ \text{is } \max(0, \text{HVDC}_{\text{Risk}t} - (h * \text{INJ}_D) - E^{\text{IR}}_{\text{HVDC}t}) = m_{ht} \text{ for the} \\ \text{HVDC link} \end{array} \right.$

M_t is $\sum_x m_{xt} + m_{ht}$

h	is 0.5 MWh/MW
INJ_{GENxt}	is the electricity injected (expressed in MWh) by at-risk generation generating unit x in trading period t into the North Island or South Island as appropriate
E^R_{GENxt}	is the quantity of any instantaneous reserve provided under any alternative ancillary service arrangements for instantaneous reserve authorised by the system operator for at-risk generation generating unit x in trading period t
$HVDC_{Riskt}$	is the at risk HVDC transfer (expressed in MWh) in trading period t into the North Island or South Island as appropriate
E^R_{HVDCt}	is the quantity of any instantaneous reserve provided under any alternative ancillary service arrangement for instantaneous reserve authorised by the system operator for at risk HVDC transfer in trading period t
INJ_D	is 60 MW.

8.59A At-risk generation list

- (1) The system operator must publish and maintain a list of at-risk generation in accordance with this clause.**
- (2) The list must:**
 - (a) list each generating unit, or group of generating units—**
at a single GIP and
 - (i) owned by a single generator; and**
 - (ii) at or behind a single point of connection to the grid in respect of which the generator is required to submit an offer; and**
 - (iii) whose failure, including the failure of the connection assets connecting it or them to a distribution network or the grid (including via a distribution network), would be treated as a contingent event (as defined in the policy statement) under normal conditions; and**
 - (b) where a generating unit or group of generating units satisfies paragraph (a) for a limited time only, specify a start and end date and time for the inclusion of that generating unit or group of generating units in the list.**
- (3) Notwithstanding subclause (2):**
 - (a) the list must exclude any generating units or groups of generating units which comprise a subset of any other group of generating units which meets the requirements of paragraph (2)(a) (such that each generating unit is only included in one entry in the list); and**
 - (b) each generating unit or group of generating units comprising**

an entry on the list must have a total generating capacity of more than 60 MW.

(4) The **system operator** must specify in the **policy statement** how it generates and updates the list.

(5) The **system operator** may:

(a) request from any **participant** responsible for **at-risk generation** information about the generation from a **generating unit** (> 60MW) or group of **generating units** (> 60MW); ~~electricity injected~~ where that information is required to calculate allocations of ~~availability costs~~ under clause 8.59, and

(b) acting reasonably specify the time frame to provide the information, its format, and the method of delivery ~~specify a reasonable timeframe within which the information must be provided.~~

(6) A **participant** must comply with a request made under subclause (5) within the timeframe specified.

(7) Where the **system operator** already holds the information referred to in subclause (5) (e.g. from **SCADA** data), it may, by agreement with the relevant **participant**, use this information rather than requesting the information under subclause (5).

(78) For the purpose of this clause, normal conditions excludes times—

(a) when there is an outage of **grid** equipment; or

(b) during the **commissioning** of the relevant **generating unit** or group of **generating units**.