Code amendment omnibus #6: tie-breaker enhancement, materially large contracts, hedge disclosure obligations

Decision paper

30 April 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) proposed three discrete changes to trading arrangements in Part 13 of the Electricity Industry Participation Code 2010 (Code) in our *Code amendment omnibus #6* consultation. We also invited feedback on a set of technical and non-controversial Code changes.

Consultation ran for six-weeks during January and February 2026. The Authority received 11 submissions. Submitters generally supported the proposals, with substantive concerns related to the proposal for minimum offer price exclusions for tie-breaker situations.

This decision paper sets out our decisions after considering submissions. We have decided not to proceed with the minimum offer price exclusions. The amendments relating to materially large contracts (MLCs) and hedge disclosure obligations (HDOs) will be implemented, with a minor change to the MLC proposal in response to feedback. We will implement the technical and non-controversial Code amendments, with minor changes in response to feedback and two additional amendments.

The Authority regularly reviews the rules it is responsible for. This helps to ensure the rules continue to support the changing electricity sector. We use an omnibus process to consider multiple discrete proposals to amend the Code at the same time, as this is more efficient than running separate consultation processes.

Minimum offer price exclusions for tie-breaker situations

Our first proposal was to amend Part 13 of the Code to prevent intermittent generation from offering at $0.00/MWh. This proposal responded to a formal Code amendment request we received from the System Operator in October 2025. We have decided not to implement this proposed Code amendment.

The amendment was intended to improve how the market handles tie-breaker situations through reducing operational complexity and reliance on System Operator discretion.

Tie-breaker situations occur when multiple generators offer the same price at locations with limited transmission capacity, and one or more generation stations' output must be limited to avoid overloading the network. These situations are currently resolved using System Operator discretion. Less flexible generation, such as geothermal and thermal, is often prioritised to maintain system security.

We have decided not to implement the proposal

After considering submissions and further engagement with stakeholders, we found the risks of implementing this rule-based change outweigh the benefits.

We now consider a more targeted and durable approach is preferable to embedding an operational workaround in the Code and will explore alternative solutions.

Most submitters were supportive, but some had substantive concerns on the minimum price offer exclusions

We received 10 submissions on this proposal, and most were generally supportive. However, two submitters opposed the proposal. Concerns were raised about creating a potential structural disincentive for renewable generation. These concerns included risks of distorting efficient dispatch, discouraging investment in renewables and not fully reflecting physical system requirements.

Section 4 addresses our decision on the minimum offer price proposal.

Updating materially large contract rules

We also proposed changes to some of the provisions in Subpart 7 of Part 13 of the Code to clarify and simplify the rules on MLCs. These changes sought to ensure the rules are fit for purpose and easy to apply. We have decided to implement the proposal without change.

The MLC regime prohibits generators from entering into MLCs with large load users unless certain conditions are met. These conditions exist to prevent inefficient price discrimination.

The main proposed changes related to the definition of an MLC. They also related to how new intermittent generation is treated for calculating 'net quantity of electricity', which safeguards against inefficient price discrimination.

We have decided to implement the proposal with minor changes

After considering submissions, we have decided to implement the proposal with minor changes to the MLC definition.

The amendment benefits consumers by clarifying when a contract is an MLC and by supporting investment in new generation and strengthening the safeguards against inefficient price discrimination.

This amendment will come into force on 1 July 2026.

All submitters were supportive of the changes for updating materially large contract rules

All seven submissions supported the proposed amendment. One submitter thought that further Code changes should be made. In response to this, we have made a minor change to the MLC definition.

A detailed guidance notice for the interpretation of MLC provisions will be published in May 2026, separate to this decision paper.

Section 5 addresses our decision on the MLC proposals.

Updating hedge disclosure obligations to increase transparency

The third proposal was to strengthen the HDOs and improve transparency in the over-the-counter hedge market. We have decided to implement the proposal without material change.

The hedge arrangement disclosure provisions in subpart 5 of Part 13 of the Code require participants to disclose information about certain risk management contracts:

- options contracts
- contracts for difference
- fixed-price physical supply contracts (including fixed price fixed volume and fixed price variable volume).

Information is disclosed and published through the Electricity Hedge Disclosure System (hedge disclosure system), a web portal operated by NZX.

The proposals responded to operational issues identified since improvements to the hedge disclosure obligations in 2024. In addition, we also sought feedback on three technical and non-controversial Code changes.

The changes will achieve the objective of ensuring a robust set of hedge disclosure obligations, which:

- improve identification of power purchase agreements (PPAs) and firming arrangements
- introduce clear timeframes and processes for novel contracts
- require participants to provide consistent information on demand response arrangements, and
- give the Authority discretion regarding what information is made publicly available to ensure accurate comparison of risk management contracts.

We have decided to implement the proposal without change

After considering submissions, we have decided to implement the proposal without change. Together, we believe the amendment improves the function of the wholesale market, giving effect to the policy behind the 2024 improvements.

The amendment benefits consumers by enabling participants to more effectively manage their exposure to price volatility. They also provide price signals about when new electricity generation and storage investment is needed.

This amendment will come into force on 1 August 2026.

All submitters were supportive of the changes to hedge disclosure obligations

All nine submitters supported keeping the hedge disclosure system up-to-date and fit-for-purpose. Feedback from submitters focused on maintaining the confidentiality of the information and providing sufficient guidance to the participants required to disclose risk management contracts.

Section 6 addresses our decision on improving transparency of hedge disclosure obligations.

Technical and non-controversial Code amendments

We also proposed corrections to the Code for some minor typographical and other errors. These amendments are technical and non-controversial and do not change the meaning or intent of the Code.

We received minor feedback from Transpower on these amendments.

We have decided to implement the proposal with minor changes and two additions

We have decided to make the proposed amendments largely as consulted on, with some minor changes to reflect feedback.

We have also identified two additional minor amendments which were not part of the proposed corrections included with the consultation paper. These include a necessary minor amendment to a recently made Code amendment relating to the use of half hourly data for reconciliation, and a correction to a cross-referencing error. These are detailed in section 7.

These amendments will come into force on 1 August 2026, with the exception of one change, which will come into force on 1 October 2026.

Section 7 addresses our decision on our decision on technical and non-controversial Code amendments.

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1. Purpose of this decision paper

1.1. The Electricity Authority Te Mana Hiko (Authority) has decided to amend several areas of the Electricity Industry Participation Code 2010 (Code).

Code amendment omnibus #6

1.2. On 12 January 2026, we published a consultation paper: *Code amendment omnibus #6: tie*-breaker *enhancement, materially large contracts, hedge disclosure obligations* (consultation paper).[1] We consulted on three proposals to amend the Code.

1.3. This paper sets out the Authority's decisions on the three proposals and gives reasons for each decision. Tables 1 and 2 show that the proposed amendment for minimum offer price exclusions for tie-breaker situations is the only proposal that will not be proceeding.

Table 1: Amendments <u>not</u> proceeding

	Topic	Page
1	Minimum offer price exclusions for tie-breaker situations	10

Table 2: Amendments proceeding

	Topic	Effective date	Page
2	Materially large contracts	1 July 2026	13
3	Hedge disclosure obligations	1 August 2026	20
4	Technical and non-controversial Code amendments	1 August 2026, 1 October 2026	29

[1] The consultation paper is available on our website at: Code amendment Omnibus #6: tie-breaker enhancement, materially large contracts, hedge disclosure obligations

2. Submissions on Code amendment omnibus #6

2.1. We received 11 submissions on the consultation paper, from parties listed in in Table 3.[2]

2.2. Issues raised by submitters are discussed in the section for the relevant proposal.

Table 3: List of submitters

Submitter	Role	Proposal(s) addressed
Business Energy Council	Industry body	1, 2,3
Contact Energy	Generator/retailer	1, 2, 3
Energy Retailers' and Generators' Association of New Zealand (ERGANZ)	Industry body	1, 2, 3, 4
EVA Marketplace	PPA marketplace	3
Genesis Energy	Generator/Retailer	1, 2, 3
Kākāriki Renewables	Generator	1
Meridian Energy	Generator/Retailer	1, 2, 3
Ngawha Generation	Generator	1, 3
Nova	Generator	1, 2, 3
Octopus Energy	Retailer	1, 2, 3
Transpower	FTR Manager / Grid Owner / System Operator	1, 4

[2] Submissions are available on our website at: Code amendment omnibus #6 | Our consultations | Our projects | Electricity Authority

3. The amendments promote our statutory objectives and are consistent with regulatory requirements

3.1. The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic 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.

The decisions we have made are consistent with the Authority's statutory objectives

3.2. After considering all submissions on the Code amendment proposals, the Authority considers the final Code amendments will deliver long-term benefits to consumers consistent with the Authority's main objective.

The benefits of the amendments are greater than the costs

3.3. The Authority has assessed the benefits and costs of the MLC and hedge disclosure obligation amendments, and each of them delivers a net benefit. The consultation paper describes these costs and benefits in more detail.

The amendments are consistent with regulatory requirements

3.4. The Code amendments are consistent with the requirements of section 32(1) of the Act. The amendments are also consistent with the Authority's Code amendment principles.

How the amended Code wording is displayed in this decision paper

3.5. Code amendments in this decision paper are displayed as:

(a) added text or formatting is underlined

(b) deleted text is ~~strikethrough~~

(c) additional added text or formatting compared to our consultation paper are red underlined

(d) additional deleted text compared to our consultation paper is ~~red strikethrough~~.

4. Minimum offer price exclusions for tie-breaker situations

The Authority's proposal

4.1. The Authority proposed to amend the Code to exclude intermittent generators from offering at $0.00/MWh.

4.2. The proposal also included preventing intermittent generators from bidding for must run dispatch auction (MRDA) rights to apply to intermittent generation units. This was because generators could otherwise use MRDA rights to offer at $0.00/MWh and increase their likelihood of being dispatched.[3]

4.3. The proposal was intended to improve how the market handles tie-breaker situations. These situations occur when multiple generators offer the same price at locations with limited transmission capacity, and one or more generation stations' output must be limited to avoid overloading the network.

4.4. Tie-breaker situations are currently resolved using System Operator discretion. The System Operator can use discretion to prioritise which generating stations remain on to maintain system security. Less flexible generation, such as geothermal and thermal, is usually prioritised.

4.5. Limiting intermittent generators to a minimum offer of $0.01/MWh would give an automatic way to dispatch an intermittent generating station's output down when transmission is limited. Other generators would still be able to offer at $0.00/MWh, giving them priority dispatch.

We have decided not to implement the proposal

4.6. The Authority has decided to not implement the Code amendment proposal, in response to submitter feedback. Instead, we will look into a more targeted and durable approach to address the issue raised by the System Operator.

Submissions on the proposal to prevent intermittent generators from offering at $0.00/MWh for tie-breaker situations

4.7. We received 10 submissions on the proposal.

4.8. Eight submitters were in support of making the changes. Two submitters were opposed to making the changes.

4.9. This section sets out our response to issues raised by Octopus Energy (Octopus) and Kākāriki Renewables (Kākāriki).

Concern about a structural disincentive for intermittent generation and hydro considerations

4.10. Kākāriki raised the concern that preventing intermittent generation from offering at $0.00/MWh appears to create a structural disincentive for investment in intermittent

[3] The MRDA allows generators to improve their chances of being dispatched by securing rights to offer at $0.00/MWh. Some generation is considered must run because it cannot reduce output without breaching resource consents or facing operational risks. The MRDA operates at a national level so it does not account for regional transmission constraints.

generation. They considered that the proposal would weaken price signals and lead to inaccurate investment and dispatch decisions.

4.11. Kākāriki also noted that the proposal could inadvertently favour hydro over intermittent generation.

4.12. Octopus expressed concerns the proposal moves the market away from equal treatment of generation technologies.

The Authority's response to the feedback

4.13. We understand both submitters' concerns assume a potential situation where there is a widespread surplus of generation.

Perception of structural disincentive for intermittent generation

4.14. By excluding intermittent generators from offering at $0.00/MWh, intermittent generation is always curtailed in preference of non-intermittent generation. This includes circumstances where there is no system security benefit.

4.15. We recognise the proposal could create at least the perception of a structural disincentive for investment in intermittent generation. For example, investors who are not familiar with nodal dispatch and pricing solution, may perceive the $0.01/MWh offer constraint as limiting intermittent generator's ability to meet its volume commitments under future power purchase agreements (PPAs). This perception could increase the financial risk of new intermittent generation projects.

Hydro considerations

4.16. We believe the situation described in Kākāriki's submission with hydro generation is currently unlikely to occur, as other drivers mitigate the risk of widespread generation surplus.[4] However this likelihood could change with increasing investment in intermittent generation.[5]

4.17. Although only one intermittent generator has offered at $0.00/MWh since 2008, competitive pressure could result in increased numbers of zero-priced intermittent generation offers. Future intermittent generation investments relying on PPAs could motivate intermittent generators to seek zero-priced dispatch to ensure contracted volumes are being met.

4.18. These reasons contributed to the decision to not go ahead with the proposed Code change. We see value in developing a more targeted solution to mitigating surplus generation conditions.

The costs of the proposed amendment could outweigh the benefits

4.19. After reconsideration, the Authority believes that the costs of the proposed amendment could outweigh the benefits. While the proposal offered benefits, it raised material risks and may have led to unintended consequences.

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4 For example, the value of stored water reduces the likelihood of excess offered hydro generation.

5 Intermittent generation makes up around 83% of the 293 projects currently in development. See: Generation investment pipeline | Electricity Authority

4.20. In the consultation paper, we considered that the benefits did outweigh the costs. These benefits included enhanced reliability of supply and greater operational efficiency through reduced operational burden on the System Operator.

4.21. We recognise that as the proportion of intermittent generation increases, the System Operator is likely to be increasingly burdened in managing surplus generation conditions. However, it is important that mitigations for this do not disincentivise investment in new generation.

4.22. Although eight of the submitters agreed the benefits outweigh the costs of the proposed amendment, Kākāriki's and Octopus' concerns were substantive.

4.23. Given the Authority no longer considers the benefits outweigh the costs, we have decided not to implement the proposal.

We consider the status quo is preferable to implementing the original proposal

4.24. Our preferred approach is to continue with the status quo. This avoids unnecessary risks and potential costs while a more complete solution is developed that avoids negative impacts on:

(a) intermittent generation

(b) security of supply

(c) investment incentives.

4.25. Given the risks and potential costs mentioned above, we prefer to maintain the status quo in the meantime. This allows time to develop a more comprehensive solution to avoid negative impacts on intermittent generation, security of supply, and investment incentives.

4.26. We will instead explore alternative options that are more targeted and less distortionary, and that provide greater certainty for market participants. This includes revisiting the alternative options outlined in the consultation paper to see if the identified issues in those options can be avoided or resolved.[6] This could include further consideration of allocation of 'must-run' rights.

4.27. The Authority will continue to investigate a more robust solution.

[6] Electricity Authority, *Code amendment omnibus #6: tie-breaker enhancement, materially large contracts, hedge disclosure obligations consultation paper*, January 2026.

5. Improving clarity of the materially large contracts provisions

The Authority's proposals

5.1. The Authority proposed discrete changes to the materially large contracts (MLC) provisions in part 13, subpart 7 of the Code. The proposals seek to provide greater clarity for participants and other interested parties on the interpretation and application of the MLC provisions.

5.2. The MLC provisions are intended to mitigate the incentive for generators (in some circumstances) to provide inefficient subsidies to large load users that may result in other consumers facing higher prices than they otherwise would in an efficient market. The regime achieves this by prohibiting generators from giving effect to MLCs unless certain conditions are met, by imposing information disclosure requirements to support compliance and by providing for a clearance regime.

5.3. Following the introduction of the MLC provisions in 2023, the Authority has received queries from participants on the interpretation and application of certain provisions. The Authority also identified opportunities for discrete Code amendments, supported by guidelines, to improve clarity for all participants.

5.4. We identified three areas of the Code that could be amended to provide greater clarity for participants and other interested parties on the interpretation and application of the MLC provisions. These are:

(a) an amendment to the definition of an MLC in clause 13.268(1)(a) to exclude bilateral contracts where the final price the buyer pays (accounting for any discounts) is at least the spot price or is at least the same as an equivalent exchange-traded derivative or derivatives

(b) an amendment to clause 13.268(4) to enable generators to use a median generation offset for new generation (calculated according to prevailing industry standards for each energy type) for the purpose of deriving "net quantity of electricity" in clauses 13.268(1)(a)(iii) and 13.268(4)

(c) a minor amendment to the wording of clause 13.268(4) to prevent the potential for the clause to be interpreted as only applying to contracts already classified as MLCs (this clarifies the intention of the clause to apply to any contract being assessed for MLC status).

5.5. We proposed these changes to address three issues arising from the language used in the current provisions:

(a) The intention of the regime is to capture only contracts that present a genuine risk of inefficient price discrimination. Contracts of the kind described at paragraph 5.4(a) above do not present such a risk without these amendments but could be interpreted as falling within the previous definition of an MLC, potentially imposing unnecessary administrative or compliance costs on participants.

(b) The intention of the regime is also to recognise circumstances where new generation materially improves supply conditions and therefore reduces the potential for inefficient price discrimination. Under the wording of the Code

without these amendments, new intermittent generation could not be adequately accounted for (netted off) when assessing whether a contract met the MLC threshold, creating uncertainty for generators and buyers as to whether the MLC provisions applied.

(c) Without these amendments the previous drafting of clause 13.268(4) created a risk that the provision could be interpreted as applying only once a contract had already been classified as an MLC. This was inconsistent with the policy intent for the clause to apply during the assessment of any contract against the MLC definition.

5.6. Further detail on the issues with the previous MLC provisions and the intention of these amendments can be found in the previous Code amendment omnibus #6 consultation paper[7] and the MLC guidelines we intend to release alongside this paper.

We have decided to implement the proposals with minor changes

5.7. The Authority has decided to implement the proposals outlined in the consultation paper with a minor change. The Code amendment will come into effect on 1 July 2026.

5.8. We have made two small changes to the amendment to ensure alignment with policy intent and address a minor matter raised in submissions. The Authority considers these changes to be technical and non-controversial, including because they are consistent with the policy objectives outlined and consulted on. These parts of the amendment will also come into effect on 1 July 2026.

5.9. The approved Code amendment is included in section 5.33 below.

We will release guidelines to support participants interpretation of the MLC provisions

5.10. In May 2026, in addition to the amendment, the Authority will publish guidelines for the interpretation of MLC provisions on the Authority's website.. This is intended to provide further clarity to participants and other interested parties on the Authority's approach to:

(a) apply the MLC provisions

(b) improve understanding and compliance

(c) assist participants in decision making.

Submissions on the proposed MLC provisions

5.11. There were seven submissions on these proposals. All submitters broadly supported the proposals, including the Authority's preferred approach to recognising generation arising from new investment.

5.12. One submitter qualified its support for the proposal, noting it considered the Authority had missed an opportunity to address wider issues with, or make further improvement to, the MLC provisions.

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7 Electricity Authority, *Code amendment omnibus #6: tie-breaker enhancement, materially large contracts, hedge disclosure obligations consultation paper*, January 2026.

Submitters supported the change to the definition of MLC

5.13. All submitters supported explicitly excluding bilateral contracts from the definition of MLC, where the final price the buyer pays (after any discounts) is at least the spot price or is at least the same as an equivalent exchange-traded derivative or derivatives.

5.14. Submitters agreed that contracts of this nature do not have the potential to create inefficient price discrimination. This is because buyers under such contracts are effectively paying market prices. Specifically excluding these contracts in the wording of clause 13.268(1)(a) reduces any unnecessary compliance burden associated with such contracts being potentially captured within the definition of an MLC.

Submitters supported the change to the treatment of new generation offsets

5.15. All submitters supported the option for new generation to be offset according to the median MW expected to be generated by the plant or plants during all trading periods for the duration of the contract.

5.16. Submitters agreed that providing for the calculation of a generation profile in this way would more appropriately reflect the contribution of new intermittent generation over the life of a contact, removing the potential roadblock to investment in this type of generation. They also considered that giving generators flexibility in choosing an approach to calculate the offset (provided the approach complies with established market standards for each new generation type) is helpful to reflect unique or differing contract and asset characteristics.

Submitters supported the change to the wording of clause 13.268(4)

5.17. All submitters supported, or did not comment on, the proposed wording change to clause 13.268(4) on the basis it removes the logical flaw in the previous drafting.

One submitter considered that further Code amendments were warranted

5.18. In its submission, Meridian Energy argued the current MLC provisions do not adequately deal with smaller contracts in circumstances where there is broad retail competition for contracts in respect of multiple sites across New Zealand or for customers “wedded to New Zealand” that pose minimal exit risk.

5.19. They also considered that further amendments to the Code could clarify that smaller variable volume contracts are not intended to be captured by the definition of an MLC. Smaller variable volume contracts may not include explicit contractual limits on maximum consumption but, in practice, cannot exceed the 150 MW threshold due to factors such as connection capacity constraints. Accordingly, Meridian suggested the Code should be amended to specify that generators should estimate *likely* maximum consumption when assessing a contract rather than *theoretical* maximum consumption.

5.20. Meridian supported the proposal to the extent that it addressed circumstances where significant proportions of a customer’s load are priced based on spot prices plus a margin (ie, undiscounted market prices) as these contracts cannot create an inducement for a load customer to stay given it will be paying no less than market prices.

The Authority's response to the submissions

5.21. We recognise the issue raised by Meridian in its submission regarding contracts which may not include explicit limits on consumption but where consumption cannot practically exceed 150MW and consider that this can be appropriately dealt with by an additional amendment to the definition of an MLC. Therefore, we have decided to also amend clause 13.268(3). This is to clarify that where a contract allows for varying quantities of electricity consumption at any one time, the quantity of electricity consumption *that is practically and physically* possible at any one time is to be used for determining whether the MW threshold is met.

5.22. We consider that this change supports the policy objective of limiting the application of the MLC provisions to contracts above a certain size. However, we note that if parties continue to have concerns and in cases where there is no realistic possibility of consumption exceeding the 150MW qualifying threshold at a 'point in time' over the duration of the contract, parties can consider including an express ceiling of less than 150MW in their contract.

5.23. The MLC guidelines will also clarify that the Authority will still rely on generators to demonstrate that actual consumption at a 'point in time' will not reach the 150MW threshold. Evidence for this could include:

(a) maximum load at the sites covered by the agreement (total consumption of all major equipment and systems operating simultaneously)

(b) supply constraints such as connection and transmission link limitations

(c) demand diversity evidence such as historical usage patterns and future operating models.

5.24. Further detail on interpreting the MLC provisions with respect to variable volume contracts with no explicit consumption ceilings will be provided in the MLC guidelines.

Additional amendment to clause 13.268

5.25. We have also decided to implement another minor change to the definition of an MLC in clause 13.268(1) which we consider to be technical and non-controversial including because it is consistent with, and implements, the policy objectives previously consulted on.

5.26. This amendment clarifies that for the purpose of assessing whether two or more contracts meet the definition of an MLC, it is only necessary for one of the contracts to result in a price paid by the buyer (accounting for any discounts) that is less than the price of an equivalent exchange traded derivative(s) or the spot price for any trading period during the contract's term, where the contracts together reach the 150MW threshold.

5.27. The final Code amendment is set out at paragraph 5.35 below.

The amendment will promote efficient operation of the electricity industry

5.28. The Code amendment is consistent with the Authority's main statutory objective, and sections 32(1)(c) and 32(1)(e) of the Act, because they will:

(a) provide greater clarity to participants and interested parties on how to interpret and apply the MLC provisions

(b) support the main policy objective of reducing inefficient price discrimination

(c) promote the efficient operation of the electricity industry and the Authority's performance of its functions.

The benefits of the proposed amendment outweigh their costs

5.29. In the consultation paper, we considered that the benefits of the proposed amendment outweigh the costs. The expected net benefits include reduced uncertainty for investors in new generation assets and reduced compliance costs while preserving safeguards against inefficient price discrimination.

5.30. All submitters who commented on the regulatory impact statement agreed that benefits of the proposed amendment outweigh the costs. However, ERGANZ qualified its position on the basis the regime should be periodically reviewed to ensure it remains well-calibrated in the future.

5.31. We remain of the view that the benefits of the proposed amendment outweigh their costs and will continue to monitor their performance.

We consider our approach is preferable to alternatives

5.32. As noted in the consultation paper, we considered the alternatives of retaining the status quo (ie, not amending clause 13.268(4) to create further provision for new intermittent generation offsets) and issuing guidelines without accompanying Code amendments.

5.33. The Authority considers our decision to amend the Code while also providing accompanying guidelines is preferable to these alternatives on the basis that:

(a) the status quo would not provide a meaningful offset for new intermittent generation (which can be near zero in any trading period). Therefore, it would not materially differentiate contractual arrangements which attract new intermittent generation from those that do not

(b) guidelines alone would be insufficient to clarify the key interpretation issues discussed above.

The Code amendment aligns with our main statutory objective

5.34. For the same reasons as noted at paragraph 5.28 above, we consider that the proposals' benefits support the Authority's main statutory objective under section 15 of the Electricity Industry Act 2010.

Final Code amendment

5.35. The Code amendment will come into force on 1 July 2026. It has been approved as follows:

Electricity Industry Participation Code 2010

Part 13
Trading arrangements

13.268 Definition of materially large contract

(1) A **materially large contract** is—

(a) a contract that—

(i) is not entered into through a derivatives exchange; and

(ia) results in a final price paid by the **buyer** (after accounting for any discounts) of less than:

(A) the price of an equivalent exchange traded derivative or derivatives; or

(B) the spot price, for any trading period during the term of the contract; and

(ii) includes terms under which the buyer itself will consume electricity; and

(iii) relates to a net quantity of electricity that equals or exceeds 150 MW consumed at a point in time; or

(b) two or more contracts where:

(i) all the contracts satisfy paragraph (a)(i) ~~and (ia)~~; and

(ii) at least one contract satisfies paragraph (a)(ii) and at least one contract satisfies paragraph (a)(ia); and

(iii) the contracts when taken together satisfy paragraph (a)(iii) and meet one of the descriptions set out in paragraph (c) below:

(c) the descriptions referred to at paragraph (b)(iii) above are:

(i) two or more contracts between a **generator** and a **buyer**; or

(ii) at least one contract between a **generator** and a **buyer** and at least one contract between that **generator** or its related company and that **buyer** or its related company; or

(iii) at least one contract between a **generator** and a **buyer** and at least one contract involving a second **generator** and the same **buyer** where the contracts rely on each other or are otherwise interdependent; or

(iv) at least one contract between a **generator** and a **buyer** and at least one contract between the same **generator** and a second **generator** where the contracts rely on each other or are otherwise interdependent; or

(v) any other arrangement that is substantially of the same kind as that described in any of subparagraphs (i)-(iv).

(2) For **materially large contracts** made up of two or more different **generators'** contracts, any reference to **materially large contract** in the following clauses must be read as only referring to an

individual **generator's** contract(s) that forms part of a **materially large contract**, rather than as a reference to the multiple **generators'** contracts.

(3) Where a **materially large contract** allows for the possibility of varying quantities of **electricity** consumption at any one time, the maximum quantity of **electricity** consumption practically and physically possible under the contract at any one time, given the equipment or plant at the **buyer's ICP**, is to be used for the purpose of determining whether the **MW** threshold in subclause (1)(a)(iii) is met.

(4) For the purpose of subclause (1)(a)(iii), the net quantity of **electricity** is the ~~total~~ **MW** consumed at a point in time (calculated in accordance with subclause (3)) less any **MW** generated from new generation (calculated in accordance with subclause (5)), where the ~~**materially large contract**~~ contract is material to the **generator's** decision to invest in the new generation.

(5) For the purposes of subclause (4), **MW** generated from new generation is:

(a) the median **MW** expected to be generated by the new **generating station** in any **trading period** over the contract period following its **commissioning**, to be calculated using relevant industry standards for resource assessment data and accounting for all relevant factors reasonably expected to affect the new **generating station**'s contribution to the **grid**, including (without limitation and to the extent applicable) —

(i) the efficiency of the new **generating station**:

(ii) degradation of the **generating station**'s performance over time:

(iii) the **generating station**'s operational availability:

(iv) fuel supply and quality:

(v) the impact of climate oscillations such as the El Niño-Southern Oscillation, Southern Annular Mode, or other relevant climate variability modes; or

(b) to be calculated using an alternative methodology which is robust and supported by evidence that meets or exceeds industry standards for the appropriate resource assessment.

(~~5~~ 6) For the purpose of this subpart, related company has the meaning set out in section 2(3) of the Companies Act 1993.

6. Improving transparency of hedge disclosure obligations

The Authority's proposals

6.1. We proposed five amendments to Part 13 of the Code, an update to published guidance, and a change to the hedge disclosure system. These were proposed to keep the hedge disclosure system fit-for-purpose. Our proposals responded to operational issues identified since changes made to the hedge disclosure obligations in 2024.[8]

6.2. The proposals aimed to enhance confidence in market competitiveness, maintain sufficient regulatory oversight and increase transparency in the over-the counter market.

6.3. The key proposals were measures to:

(a) improve identification of power purchase agreements and firming arrangements

(b) introduce clear timeframes and processes for disclosing novel contracts

(c) require participants to provide consistent information on demand response arrangements

(d) ensure accurate comparison of risk management contracts and development of accurate contract curves by providing the Authority with discretion to not publish information on a risk management contract if doing so would not achieve this purpose.

6.4. We also proposed technical and non-controversial changes to the hedge disclosure obligations. These were to fix an error in the formulas in clause 13.220 and to clarify the relationship between subclauses 13.226A(1) and (2) to more clearly reflect the policy intent.

6.5. The final two proposals, to publish guidance on reporting of trade date and to add more choice to option style in the hedge disclosure system, do not require a Code amendment. They were included in the consultation paper for completeness.

We have decided to implement the proposals without change

6.6. The Authority has decided to implement the proposals without material change. The Code amendment will come into force on 1 August 2026. We will also update guidance documents for the hedge disclosure system.

6.7. No changes to the proposed Code amendment are required to address concerns raised by the submissions. Although some additional interpretation issues were raised, we consider these are adequately addressed through guidance and do not necessitate further changes to the Code amendment. We have made one technical change to correct a typographical error.

6.8. The approved Code amendment is included in section 6.35 below.

[8] Electricity Authority, *Improving Hedge Disclosure Obligations Decision paper*, June 2024.

Feedback on the hedge disclosure proposals and our response

6.9. We received nine submissions on our proposals.

6.10. All submitters supported improving the transparency of hedge disclosure obligations and the hedge disclosure system. Several submitters emphasised the need to maintain confidentiality of information on generating station and demand response. Two submitters asked for guidance on how to report demand response provisions which could be embedded within broader contracts. One submitter also suggested a different way of specifying the trade date when disclosing contracts.

6.11. Submitters did not comment on the technical and non-controversial proposals, or on the proposed change to the hedge disclosure system to add more choice to option style.

Submitters supported amending the Code to improve identification of PPAs and firming arrangements

6.12. This amendment addresses the problem that the relevant obligation in the Code to enable identification of PPAs – 'whether price (or prices) in the contract are linked to consumption or generation' – also captured firming contracts.

6.13. All submitters supported the proposed Code amendment to require the disclosure of the relevant generating station or stations (or proposed generation project if the generating station is not yet complete) if the price/s in the contract are linked to generation. This information will enable the Authority to clearly differentiate between PPAs and firming contracts and avoid the need for additional follow up to clarify the contract type.

6.14. Five submitters stressed the information should not be published at an individual contract level and should be sufficiently anonymised and aggregated to ensure pricing for individual bilateral contracts is not discoverable.

Authority response

6.15. The Authority acknowledges participants' concerns about disclosing commercially sensitive information about contracts and confirms that, under the proposal, the information will not be published on an individual contract level. Requiring this information to be disclosed to the Authority will however enhance its market facilitation, monitoring and enforcement functions. We would only disclose this information in anonymised or consolidated form to protect confidentiality, consistent with our obligations under clause 13.233 of the Code.

Submitters supported amending the Code to introduce timeframes and processes for disclosing novel contracts

6.16. This amendment addresses the problem that because novel contracts were not technically defined as risk management contracts under the Code, the standard timeframe obligations do not apply.

6.17. The eight submitters who commented on this proposal agreed that a 10-business day timeframe for submission of information, and the same process requirements as those applying to risk management contracts, should be introduced for novel or other types of contracts. Submitters recognised that this would reduce uncertainty

around expectations while still giving sufficient time for participants to disclose these contracts.

Submitters supported amending the Code to require participants to disclose information on demand response

6.18. This amendment addresses the problem that the different ways in which demand response contracts could be disclosed in the hedge disclosure system created confusion and risked different and incomplete information being disclosed.

6.19. All seven submitters who commented on this proposal supported requiring disclosure of information on demand response. Genesis and the Electricity Retailers and Generators Association of New Zealand requested guidance on how to report demand response provisions.

6.20. Meridian noted that publishing anonymised and aggregated information about fixed-price physical supply contracts that include demand response needs careful handling. This is because these contracts can distort price discovery with lower average prices compared with standard contracts.

Authority response

6.21. Under this proposal, it will be evident when an individual contract is or includes a demand response. This information will be published under clause 13.226A. The Authority plans to publish this information in a way that such contracts can be filtered out of hedge contract search results. We think this provides a good way of providing meaningful comparison between contract types compared to the current situation where demand response contracts are not treated as a specific type of risk management contract. Other information provided about demand response contracts (including demand response price, premium, the duration of demand response provision and the specified volume of electricity) will not be published at an individual contract level.

6.22. We agree that guidance would be desirable to support disclosure of information on demand response. We will update the *Hedge Disclosure System User Guide* to include this information when the Code amendment comes into force.

Submitters supported amending the Code to provide the Authority with discretion in making information publicly available

6.23. This amendment addresses problems created by the obligation on the Authority to publish specified information in relation to every risk management contract disclosed without exception. We identified that in certain cases (such as when a risk management contract is transferred to another party, and a back-to-back contract is agreed that mirrors the original contract), publishing the information could distort the OTC contract information.

6.24. All seven submitters who commented on this proposal supported it. Submitters recognised that back-to-back contracts reflecting historical prices could distort contract price curves if published through standard processes and could also reveal commercially sensitive information given the small number of participants likely to be involved. The submitters agreed that discretion in what the Authority publishes should improve confidence in price information and better align publication with the objectives of the hedge disclosure obligations.

Guidance on specification of the trade date

6.25. We proposed to update hedge disclosure system guidance to specify that parties to risk management contracts who are required to submit information should agree on how the trade date is reported at the time of agreeing to the contract.

6.26. Meridian argued the Authority should define "trade date" in the Code, rather than leaving parties to decide how to report it. It argued that because the date a contract is agreed often differs from the date a confirmation is physically signed, using the later execution date could misrepresent market conditions at the time prices were actually agreed.

6.27. Meridian also noted that chasing counterparties for signatures can delay execution and distort hedge disclosure. It suggested amending the Code so that "trade date" is expressly defined as the date the contract is agreed, without requiring formal signature to avoid extra negotiation steps and support automation of disclosure processes.

Authority response

6.28. We acknowledge the issue raised by Meridian but consider that this can be appropriately dealt with through guidance as proposed, rather than a Code amendment. Provided participants observe the hedge disclosure guidance, we do not expect the risk of inconsistent application of trade date to be material.

The amendment will promote competition in, and efficient operation of, the electricity industry

6.29. The Code amendment is consistent with the Authority's main statutory objective, and sections 32(1)(a) (competition in the electricity industry), 32(1)(c) (efficient operation of the electricity industry) and 32(1)(e) (performance by the Authority of its functions) of the Act. This is because they support investment in generation through greater visibility of PPAs and increase regulatory oversight of the OTC market, which is aligned with the long-term interests of consumers.

We consider our approach is preferable to alternatives

6.30. The alternatives are to retain the status quo by not making the proposed Code amendment or updating hedge disclosure guidance documents without accompanying Code amendment.

6.31. We consider that our decision to amend the Code and guidance documents for the hedge disclosure system is preferable to these alternatives because:

(a) the status quo does not provide sufficient visibility of PPAs or allow sufficient differentiation of demand response contracts

(b) updating guidance alone would not be sufficient for continued regulatory oversight of the OTC market.

We expect our proposals to result in benefits that would support the statutory objectives

6.32. In the consultation paper's regulatory statement, we considered that the benefits of the proposed amendment outweigh the costs. The expected net benefits of better

market data quality include more effective hedging strategies, competitive pricing, and reduced information asymmetries.

6.33. The three submitters who commented on the regulatory statement agreed with the analysis and that the proposed Code amendment is preferable to the alternatives.

6.34. Retailers, generators and traders will need to adjust internal reporting and contract-capture processes to meet new disclosure requirements. Enhanced scrutiny of demand-side hedging arrangements and PPAs will require more detailed contract classification from participants.

6.35. We expect the overall compliance impact to be low, with most changes building on existing processes. We believe that the benefits of the proposed amendment outweigh the costs.

Final Code amendment

6.36. The Code amendment will come into force on 1 August 2026. It has been approved as follows:

Part 1 – Interpretation

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

…

buyer, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) in respect of a **contract for differences**, the fixed-price payer, being the **party** obliged to make payments at a fixed price from time to time during the **term** of the contract; or

(b) in respect of a **fixed-price physical supply contract** or a **demand response contract**, the purchaser of **electricity**; or

(c) in respect of an **options contract** either—

(i) the **party** paying the **premium**; or

(ii) if there is no **premium**, the **party** who agrees to be the **buyer** for the purposes of subpart 5 or subpart 7 (as applicable) of Part 13; or

(iii) if neither **party** agrees to be the **buyer**, the **party** whose name is the first alphabetically; or

(ca) for the purposes of subpart 5 of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**, either—

(i) the **party** specified as the buyer in the contract; or

(ii) if neither **party** is specified as the buyer, the **party** whose name is the first alphabetically; or

(d) for the purposes of subpart 7 of Part 13, in respect of any other contract, the **party** consuming the **electricity** that the contract relates to

…

demand response contract means a contract containing the right to reduce the consumption of **electricity** by an amount that equals or exceeds 0.1 **MW** of **electricity**

demand response premium, in relation to a **demand response contract**, means the dollar amount paid by the **seller** to the **buyer**

demand response price means the price paid to the **consumer** for each **trading period** during which the **consumer** reduces their consumption of **electricity** under a **demand response contract**

…

risk management contract, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) a **contract for differences**; or

(b) a **fixed-price physical supply contract**; or

(c) an **options contract**; or

(caa) for the purposes of subpart 5 of Part 13, a **demand response contract**; or

(ca) for the purposes of subpart 5 of Part 13, a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**; but

(d) does not include an **FTR**

…

seller, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) in respect of a **contract for differences**, the **floating-price payer**; or

(b) in respect of a **fixed-price physical supply contract** or a **demand response contract**, the **party** selling the **electricity**; or

(c) in respect of an **options contract**, either—

(i) the **party** receiving the **premium**; or

(ii) if there is no **premium** under the **options contract**, the **party** who agrees to be the **seller** for the purposes of subpart 5 or subpart 7 (as applicable) of Part 13; or

(iii) if neither **party** agrees to be the **seller**, the **party** whose name is the second alphabetically; or

(ca) for the purposes of subpart 5 of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**, either—

(i) the **party** specified as the seller in the contract; or

(ii) if neither **party** is specified as the seller, the **party** whose name is the second alphabetically; or

(d) for the purposes of subpart 7 of Part 13, in respect of any other contract, the **party** who is not the **buyer**

Part 13 – Trading arrangements

Subpart 5 – Hedge arrangement disclosure

13.219 Information that must be submitted

(1) The party specified in clause 13.218 must submit the following information to the **approved system** in relation to every **risk management contract**, excluding exchange-traded **risk management contracts** where the **parties** have provided consent under clause 13.236AA:

(a) each **party's** legal name:

(b) each **party's** email address for notice:

(c) the **trade date**:

(d) the **effective date**:

(e) the **end date**:

(f) the **quantity**:

(g) whether the contract is a **contract for differences**, a **fixed-price physical supply contract**, an **options contract** or, if the contract is a type of **risk management contract** prescribed by the **Authority** under clause 13.219B, the type of **risk management contract**:

(ga) whether the contract is or includes a **demand response contract**:

(gb) if the contract is or includes a **demand response contract—**

(i) the **demand response price**, if specified in the contract:

(ii) if no **demand response price** is specified, whether consideration for exercising a right to demand response in the contract is linked to:

(A) price(s) in the contract referred to in subclause (l); or

(B) other agreements between the parties (in which case, this must be specified):

(iii) the minimum and maximum duration of demand response provision under the contract:

(iv) the specified volume of **electricity** by which consumption may be reduced:

(iii) the minimum notice period prior to exercising a right to demand response:

(iv) the limits, if specified, on repeated use of the demand response provisions:

(v) the **demand response premium**, if specified in the contract:

(h) if the contract is an **options contract**—

(i) whether it is a call option or a put option; and

(ii) if it is a call option, whether the **buyer** has the right to buy less than the **quantity**; and

(iii) whether it is a cap option or floor option; and

(iv) the option style (for example, American or Asian):

(i) the fuel type (for example, solar, wind, thermal, or hydro), if specified in the contract:

(j) the **premium**, if specified in the contract:

(k) the **trading periods** during which each price in the contract applies:

(l) in relation to each **trading period** during which a price (other than **demand response price**) in the contract applies—

(i) the **node** at which each price is set; and

(ii) the price or series of prices to be paid at each relevant **node**; and

(iii) if applicable, the specified volume of electricity for each price to be paid at each relevant **node**:

(m) whether price (or prices) in the contract are linked to consumption or generation of **electricity**:

(ma) if the price (or prices) in the contract is linked to generation of **electricity**, the **generating station** or **generating stations**, or the proposed generation project, the contract is linked to:

(n) whether there is an **adjustment clause**:

(o) whether there is a **force majeure clause**:

(p) whether there is a **special credit clause**:

(q) whether there is a **suspension** clause:

(r) whether there are any other clauses providing for the pass-through of certain costs, levies or tax or some form of carbon-related cost:

(s) whether the contract uses any version of the International Swaps and Derivatives Association Master Agreement (ISDA Master Agreement) (including where the

schedule to the form of the ISDA Master Agreement used for the contract makes an amendment to the main part of the ISDA Master Agreement):

(t) any other information specified in a notice **published** by the **Authority** under clause 13.219A.

(2) The party specified in clause 13.218 must submit the information required by this clause in the form specified by the **Authority** and in accordance with clause 13.225(1).

13.220 Calculation of contract prices

…

(2) The **time weighted contract price** is to be calculated in accordance with the following formula:

$$CP_{tw} = \frac{\left\{ \frac{\sum_{i=1}^{n} P_i \times TP_i}{\sum_{i=1}^{n} TP_i} \right\}}{LF \times LAF}$$

…

(3) The **load weighted contract price** is to be calculated in accordance with the following formula:

$$CP_{lw} = \frac{\left\{ \frac{\sum_{i=1}^{n} P_i \times V_i}{\sum_{i=1}^{n} V_i} \right\}}{LF \times LAF}$$

…

13.222A Information about other contracts that must be submitted

(1) If a **participant** enters into a contract where a substantial purpose is to manage risk for the **participant** in relation to the spot market for **electricity**, but that contract is not a **risk management contract**, the **participant** must submit to the **approved system**:

(a) notification that the **participant** has entered into the contract; and

(b) a description of the key terms of the contract.

(2) The information specified in subclause (1) must be submitted to the **approved system** no later than 5pm, 10 **business days** after the date the **participant** entered into the contract.

(3) If both parties to the contract are **participants**, the obligation in subclause (1) only applies to:

(a) the **participant** specified as the seller in the contract; or

(b) if neither party is specified as the seller, the person whose name is second alphabetically.

(4) Clauses 13.223, 13.224, 13.227 and 13.227A apply with all necessary modifications as if the contract were a **risk management contract**.

…

13.226A Authority must make certain information publicly available

(1) Unless ~~Subject to~~ subclause (2) applies, the **Authority** must, as soon as practicable after the **WITS manager** makes information available to the **Authority** under clause 13.226(1), **publish** the following information in relation to every **risk management contract**:
  (a) information submitted under clauses 13.219(1)(c) to 13.219(1)(ga), 13.219(1)(h), 13.219(1)(j), ~~and~~ 13.219(1)(m), and 13.219(1)(n) to 13.219(1)(s):
  (b) information made available under clauses 13.226(1)(b) to (e):
  (c) where any information is submitted under clauses 13.223(1) and 13.224, —
    (i) that information, to the extent that it modifies, amends, or corrects information **published** under paragraph (a); and
    (ii) any necessary amendment to the information **published** under paragraph (b).

(2) If the **risk management contract** is for the purchase of **electricity** linked to **generation** at a particular **generating plant** or **generating plants**, or **generating station** or **generating stations**, the **Authority** must ~~may also~~ **publish** the following information in relation to the **risk management contract**:
  (a) information submitted under clauses 13.219(1)(c), 13.219(1)(f) to 13.219(1)(ga), 13.219(1)(h), ~~and~~ 13.219(1)(m), and 13.219(n) to 13.219(1)(s):
  (b) information made available under clause 13.226(1)(b):
  (c) where any information is submitted under clauses 13.223(1) and 13.224,—
    (i) that information, to the extent that it modifies, amends, or corrects information **published** under paragraph (a); and
    (ii) any necessary amendment to the information **published** under paragraph (b).

(2A) The **Authority** is not required to **publish** information under subclause (1) or (2) if **publication** would not achieve a purpose specified in clause 13.217.

(3) When information submitted under clause 13.219 or 13.223(1) is first **published** under subclause (1) or (2), the **Authority** must indicate that the information is unverified.

(4) The **Authority** must, as soon as practicable, update the indication made under subclause (3) to verified, pending verification, not disputed, disputed or subject to a long-term dispute every time the **WITS manager** notifies the **Authority** of a change in accordance with clauses 13.227(1) to (3), 13.227(4) and 13.227A(4).

7. Technical and non-controversial Code amendments

The proposal

7.1. The consultation paper also included a proposal to correct minor typographical and other errors in the Code. This included outdated cross-references, incorrectly bolded terms, and other minor drafting errors. None of the proposed amendments were intended to alter the meaning of the Code.

7.2. These amendments are considered technical and non-controversial under section 39(3)(a) of the Act. The Authority is required to publicise a draft of the proposed technical and non-controversial changes. However, we were not required to prepare a regulatory statement or consult on the proposed amendments (however, we did invite feedback).

We have decided to implement the amendments with minor changes

7.3. The Authority has decided to make the proposed amendments largely as proposed in the consultation paper, with some minor changes to reflect the System Operator's feedback.

7.4. We intend to make two further amendments not included in the consultation paper, following publication of these draft amendments in this decision paper,[9] to:

(a) correct a typographical error in clause 11.30B(5) of the Code (row 68A of the following table), and

(b) make a minor consequential amendment to clause 8 of Schedule 15.3 of the Code as a result of the Electricity Industry Participation Code (Half Hourly Data for Reconciliation) Amendment 2026 (row 143A of the following table).

Transpower's submissions and the Authority's response

7.5. One submission was received on this part of the consultation paper, with submitter Transpower (as System Operator) commenting on seven of the 147 proposed amendments.

Proposed change 42

7.6. In relation to proposed change 42 (Schedule 8.3, Technical Code A, clause 7(1)(c)), Transpower submitted that rather than replacing "**excluded generator**" with "excluded **generator**" as proposed, it would be preferable to replace it with "**excluded generating station**". That is the defined term in the clause 8.21(1) cross-reference.

7.7. We agree and have decided to make that change.

Proposed change 89

7.8. In relation to proposed change 89 (Schedule 12.4, clause 3), Transpower submitted that rather than replacing "grid point of injection" with "**grid injection point**" as

[9] Under section 39(3) of the Act, these changes do not require consultation, as the change to clause 11.30B(5) is a technical, non-controversial change under section 39(3)(a), and the change to clause 8 of Schedule 15.3 has been the subject of adequate prior consultation in October 2025, in accordance with section 39(3)(c).

proposed, it would be preferable to replace it with "**grid point of connection**". Transpower submitted that this is in the defined term in the Transmission Pricing Methodology (TPM) and the original drafting was inaccurate.

7.9. We agree and have decided to make that change.

Proposed change 90

7.10. In relation to proposed change 90 (Schedule 12.4, clause 3), Transpower submitted that clause 8 of the Schedule already addresses the significance of bolding in the TPM.

7.11. We agree and have decided that this proposed change is not necessary.

Proposed change 107

7.12. In relation to proposed change 107 (Schedule 12.6, clause 37.2), Transpower suggested that the entire clause could be deleted as no longer being necessary. This is beyond the scope of this decision, but we have made a note of this for possible inclusion in a future Code review programme. Transpower submitted that, if the clause was being retained, the word "demand" should be emboldened as a defined term.

7.13. We agree and have decided to make this change.

Proposed change 122

7.14. In relation to proposed change 122 (clause 13.205), Transpower submitted that rather than replacing "**constrained on payment**" with "constrained on payment" as proposed, it would be preferable to replace it with "**constrained on amount**" and the acronym "TCONP" with "TCONA" in all places it occurs in that clause and formulae.

7.15. This is beyond the scope of this decision, but we have made a note of this for a future Code review programme.

Proposed change 134

7.16. In relation to proposed change 134 (Schedule 13.3, clause 16(1)), Transpower submitted that rather than replacing "**reserve prices**" with "reserve prices" as proposed, it would be preferable to replace it with either "**instantaneous reserve** prices" or "**fast instantaneous reserve** and **sustained instantaneous reserve** prices". This is beyond the scope of this decision, but we have made a note of this for possible inclusion in a future Code review programme.

7.17. We have decided at this time to make the formatting change as proposed in the consultation paper.

Additional Code change suggestions

7.18. In its submission, Transpower queried the rationale for the Code's inclusion of MWh and MW as defined terms. We accept that these terms are commonly understood in the industry and it is arguable whether they need to be listed in the Code as defined terms. However, we consider, on balance, that inclusion of these terms is helpful on the basis that they are abbreviations.

7.19. Transpower also identified some technical and non-controversial amendments that could be made to Schedule 12.4 of the Code, including corrections to clause 8(e) and 117(2). These are outside the scope of this decision paper, but we have made a note of these for a future Code review programme.

7.20. We appreciate Transpower bringing these to our attention.

Correcting an error in clause 11.30B(5)

7.21. Clause 11.30B requires retailers to provide information on a comparison and switching site identified by the Authority's website, including on the retailers' websites and in communications with consumers.

7.22. Clause 11.30B(5) requires retailers to change these requirements when the Authority changes the website address or platform or creates a new platform for the same purpose.

7.23. When notifying the change to the new Billy website, the Authority identified a typographical error in clause 11.30B(5) of the Code where it refers to changing the information published or provided under clause 11.30A (which relates to dispute resolution information) rather than clause 11.30B.

7.24. Clause 11.30B(5) will be amended to replace the reference to clause 11.30B with clause 11.30A.

Consequential amendment to clause 8 of Schedule 15.3

7.25. The Electricity Industry Participation Code (Half Hourly Data for Reconciliation) Amendment 2026 (the Amendment) was made on 30 March 2026 and comes into effect on 1 October 2026. The Amendment requires electricity traders to submit aggregated half-hourly volume information to the reconciliation manager for all ICPs where there is a half-hour capable meter installed.

7.26. Schedule 15.3 of the Code sets out how participants are to calculate and provide information to the reconciliation manager. Clause 2, as amended by the Amendment, provides that, if a reconciliation participant is required to prepare submission information for an NSP, that information must comprise half hour volume information for each category 1 or category 2 metering installation that is a half-hour metering installation.

7.27. Clause 8(2) of the same schedule provides that for each category 1 or 2 metering installation, the responsible participant must provide either half-hour information, non half hour information, or a combination in certain circumstances. The reference to non half hour information is potentially inconsistent with the newly amended clause 2 obligation.

7.28. In order to clarify the obligation, we are making a consequential amendment to clause 8(2)(b) to limit the provision of non half hour information to the circumstances set out in clause 2(1)(ad), that is where the information contains only non half hour metering.

Final Code amendment

7.29. The Code amendment will come into force on 1 August 2026, with the exception of the amendment relating to clause 8(2) of Schedule 15.5 which will come into force on 1 October 2026. It has been approved as follows:

#	Clause	Decision
1.	1.1(1) – definition of **bank**	**bank** means a registered bank within the meaning of the ~~Reserve Bank of New Zealand Act 1989~~ Banking (Prudential Supervision) Act~~)~~ 1989 that is carrying on in New Zealand the business of banking
2.	1.1(1) – definition of **bona fide physical reason**	**bona fide physical reason** includes,— … (ba) in relation to an **intermittent generator**, a situation in which the **intermittent generator** reduces the output of an **intermittent generating station**— … (iv) in anticipation of the expected onset of a weather event that would be likely to cause the **intermittent generating station's asset** protection systems to shut down **assets** forming part of the **intermittent generating station**; and …
3.	1.1(1) – definition of **capacity reserve**	~~**capacity reserve** means —~~ ~~(a) demand that can be decreased for the purpose of adjusting a **constraint**; or~~ ~~(b) generation that can be increased or decreased for the purpose of adjusting a **constraint***~~ *[Revoked]*
4.	1.1(1) – definition of **designated transmission customers**	**designated transmission customer** means a **participant** who is required to enter into a **transmission agreement** with **Transpower** under subpart 2 of Part 12 **designated transmission customers** ~~means **participants** who are required to enter into **transmission agreements** with **Transpower** under subpart 2 of Part 12~~ *[Revoked]*
5.	1.1(1) – definition of **distribution network capacity**	**distribution network capacity** means the capacity of a **distribution network** to convey **electricity** under a range of load and generation conditions in accordance with **reasonable and prudent operating practice**
6.	1.1(1) – definition of **financial year**	**financial year** means, except in Part 6A and Schedule 12.4, the financial year adopted by a **participant** from time to time, being a 12 month period as a **participant** determines
7.	1.1(1) – definition of	**forecast reserve prices** means the prices for **fast instantaneous reserve** and **sustained instantaneous reserve** for each **island** scheduled in the

#	Clause	Decision
	forecast reserve prices	**price-responsive schedule** or the **non-response schedule** (whichever is relevant) in dollars and cents
8.	1.1(1) – definition of **incremental costs**	**incremental costs**, for the purpose of Part 6, means: … (b) the **distribution** costs … that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**~~.~~
9.	1.1(1) – definition of **interconnection asset**	**interconnection asset**, for the purposes of subparts ~~2,~~ 6 and 7 of Part 12— (a) has the meaning set out in the **transmission pricing methodology**; and (b) includes the **HVDC link**
10.	1.1(1) – definition of **net purchase quantity assessment**	**net purchase quantity assessment** means the quantity of an **ancillary service** derived from the following formula: a = b – c where … b is the gross amount of an **ancillary service** that the **system operator** believes is required in order to meet the **principal performance** ~~**objectives**~~ **obligation**; …
11.	1.1(1) – definition of **node**	**node** means— … (b) a location at which an electrical link that is not part of or does not contain a transformer, diverges or terminates (such as a "tee" point or a deviation); or …
12.	1.1(1) – definition of **notified planned outage**	**notified planned outage**, for the purposes of **Technical Code** D of Schedule 8.3, means any **planned outage** for which the **asset owner** has given notice to the **system operator** in accordance with **Technical Code** D of Schedule 8.3
13.	1.1(1) – definition of **outage**	**outage—** (a) for the purposes of **Technical Code** D of Schedule 8.3,,,
14.	1.1(1) – definition of **planned outage**	**planned outage—** (a) for the purposes of **Technical Code** D of Schedule 8.3,,,

#	Clause	Decision
15.	1.1(1) – definition of **scaling factor**	**scaling factor,** for the purpose of Appendix A of **Technical Code** C of Schedule 8.3,
16.	1.1(1) – definition of **specified person**	**specified person** has the meaning given in section ~~32(6)~~ 5 of the **Act**
17.	1.1(1) – definition of **un-modelled transmission asset**	**un-modelled transmission asset** means a transmission **asset** for which the **system operator's dispatch** optimisation model does not include **asset** ratings as a **constraint**
18.	1.1(1) – definition of **unplanned outage**	**unplanned outage**— (a) for the purposes of **Technical Code** D of Schedule 8.3,,,
19.	2.19(2) – Factors the Authority must consider before publishing notice	(2) Before **publishing** a notice under clause 2.16, the **Authority** must consider the impact of the proposed information requirements on each **participant** to whom it is proposed the notice apply.
20.	2.21 – Participants may identify confidential information	~~(1)~~ In supplying information under clause 2.20, a **participant** may identify any information for which confidentiality is sought by reason that— (a) disclosure of the information would unreasonably prejudice the commercial position of the **participant** or the person who is the subject of that information; or …
21.	2.22(5)(c) – Authority dealing with information identified as confidential	(5) Subclause (4) does not prevent the **Authority** from— … (c) disclosing the information where the **participant** who supplied the information or the person who is the subject of the information (if different from the **participant**) either: …
22.	6A.1(2)(a)(i), 6A.1(2)(ii), 6A.3(3)(a), 6A.4(3)(a), and Schedule 6A.1 clause 3I(1)(a)	… **MW** …

#	Clause	Decision
23.	Schedule 6A.1 clause 1(2)	(2) Without limiting the ordinary meaning of the expression, arm's-length includes having relationships, dealings, and transactions that…
24.	Schedule 6A.1 clause 2(2)	(2) In this schedule, a person is interested in a transaction if the person, or an associate of that person,— …
25.	7.16(2)(a) – Authority must consent to consultation before system operator consults on proposal to amend system operation document	(2) The purpose for the **Authority** consenting to consultation is to enable the **Authority** to identify to the **system operator** any issues with— (a) the proposal that may cause the **Authority** to not issue a notice to adopt the amendment under section 131B(2) of the **Act** or to not progress the amendment as a Code amendment under section 38 of the **Act**, as the case may be; …
26.	7.16(3)	(3) When requesting the **Authority's** consent, the **system operator** must provide the following information to the **Authority**: (a) the consultation information in clause 7.20(2)(a): …
27.	7.21(3)(a)	(3) The approval by the **Authority** of proposed amendments to a **system operation document**— (a) does not remove the requirement for the **Authority** to comply with either section 38 or section 131B of the **Act** in order to give legal effect to the amendments as part of the Code; and …
28.	8.5(1)(a) – Restoration	(1) If an event disrupts the **system operator's** ability to comply with the **principal performance obligations**, the **system operator** must re-establish normal operation of the power system as soon as possible, given— (a) the capability of generation, and **ancillary services**; and …
29.	8.31(1) – Grant of dispensations	(1) Subject to subclause (1A), the **system operator** must … (c) if the **dispensation** is a **generating unit dispensation** from clause 8.19(1) or (3), the **generator** must be allocated the following costs in a relevant **trading period** with respect to paragraph (a) for each of **fast instantaneous reserves** or **sustained instantaneous reserves**: $DispCost_{GENxt} = 0.5 \times * Q_{GENxt} \times * P_{IRt}$ Where

#	Clause	Decision
		$\underline{DispCost_{GENxt}}$ is the cost payable by a **generator** for **generating unit** x in any **trading period** t in which a class of **instantaneous reserves** is procured as a direct result of that **generating unit's dispensation** to ensure that the frequency does not fall below 47 Hertz or, in the South Island, below the **minimum South Island frequency** $\underline{Q_{GENxt}}$ is the **MW** amount by which **generating unit** x is unable to sustain pre-event output in **trading period** t with reference to clause 8.19(1) or (3) (as the case may be) as determined from the capabilities specified in that **generating unit's dispensation** (different amounts may be specified with respect to each class of **instantaneous reserves**)
30.	8.35(1)(d) – Revocation of equivalence arrangement and revocation or variation of dispensation	(1) The **system operator** may revoke approval of an **equivalence arrangement** or revoke or vary the grant of a **dispensation** as the **system operator** reasonably considers appropriate if, at any time after the **system operator** has approved an **equivalence arrangement** or granted a **dispensation**, the **system operator** is satisfied that 1 or more of the following apply: … (d) withdrawal is provided for under the terms of the **dispensation** granted: …
31.	8.43(a)(iv) – Content of procurement plan	A **procurement plan** must, for each **ancillary service—** (a) specify the principles that the **system operator** must apply in making a **net purchase quantity assessment**, which must include**—** … (iv) assessing the impact that **dispensations** and **alternative ancillary ~~services~~ service arrangements** held by **asset owners** will have on the quantity of **ancillary services** required to enable the **system operator** to comply with the **principal performance obligations**; and …
32.	8.58 – Frequency keeping costs are allocated to purchasers	The **allocable cost** of **frequency keeping** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula: … $\underline{Offtake_{PURxt}}$ is the total **reconciled quantity** in kWh for **purchaser** x across all **grid exit points** in **trading period** t in the **billing period** $\underline{E^{FK}_{PURxt}}$ is the quantity of any **frequency keeping** provided under any **alternative ancillary service arrangement** for **frequency keeping** authorised by the **system operator** for **purchaser** x in **trading period** t.

#	Clause	Decision
33.	8.58 – Frequency keeping costs are allocated to purchasers	Current: $\text{Share}_{PURx} = \frac{Fc * \max(0, \Sigma_t(\text{Offtake}_{PURxt} - E^{FK}{}_{PURxt}))}{\Sigma_x \max(0, \Sigma_t(\text{Offtake}_{PURxt} - E^{FK}{}_{PURxt}))}$
		Updated: $Share_{PUR_x} = \frac{F_c \times max\left(0, \sum_t (Offtake_{PUR_{xt}} - E^{FK}_{PUR_{xt}})\right)}{\sum_x max\left(0, \sum_t (Offtake_{PUR_{xt}} - E^{FK}_{PUR_{xt}})\right)}$
34.	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: … INJ_{GENxt} is the **electricity** injected (expressed in **MWh**) by **generating unit** x in **trading period** t into the North Island or South Island as appropriate …
35.	8.59 – Availability costs allocated to generators and HVDC owner	Current: $\text{Share}_t = \frac{\text{Ac}_t * \text{m}_t}{\text{M}_t}$
		Updated: $Share_t = \frac{Ac_t \times m_t}{M_t}$
36.	8.65 – Rebates paid for under-frequency events	An **event charge** that has been paid for an **under-frequency event** (referred to as "Event e") under clause 8.64 or under clause 8.64A must be rebated in accordance with the following formula to persons who are allocated **availability costs** in accordance with clause 8.59: ~~Rebate$_{xe}$~~ Rebate$_{xe}$= $EC_e * Z_{xe}/Z_{tote}$
37.	8.67(2) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and	(2) Each **connected asset owner** must pay a nominated peak kvar charge calculated in accordance with the following formula:… ~~Q_{xjz}~~ Q_{xjz} is Nom $Peak_{LINESxjz}$, which is the peak **demand** in kvar (in **zone** z) nominated to the **system operator** in advance of, and having effect from, 1 March each year by **connected asset owner** x at its **connected asset owner** kvar reference **node** j $\sum_j$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z

#	Clause	Decision
	residual charges	
38.	8.67(3) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges	(3) Each **connected asset owner** must pay a monthly peak penalty charge calculated in accordance with the following formula: … $PeakPenaltyCharge_{LINExz}$ is the total peak penalty charges for **connected asset owner** x across all **connected asset owner** kvar reference **nodes** j for **connected asset owner** x in **zone** z … $\sum_j$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z $PenaltyQuantity_{LINExjz}$ is the "kvar above nominated kvar" quantity for **connected asset owner** x at its **connected asset owner** kvar reference **node** j in **zone** z
39.	8.67(5) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges	(5) Each **connected asset owner** must pay a residual charge or receive a residual payment calculated in accordance with the following formulae: … $BillingPeriodOfftake_{LINExz}$ is the sum of **metering information** for **connected asset owner** x across all **connected asset owner** kvar reference **nodes** in **zone** z for the **billing period** for all **trading periods** $BillingPeriodOfftake_{ALLz}$ is the sum of **metering information** for all **connected asset owners** across all **connected asset owner** kvar reference **nodes** in **zone** z for the **billing period** for all **trading periods** $\sum_{xj}$ is the sum across all **connected asset owner** kvar reference **nodes** j for all **connected asset owners** x in **zone** z $\sum_j$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z Q_{xjz} is Nom PeakLINESxjz, which is the peak **demand** in kvar (in **zone** z) nominated to the **system operator** in advance of, and having effect

#	Clause	Decision
		from, 1 March each year by **connected asset owner** x at its **connected asset owner** kvar reference **node** j
40.	Schedule 8.1, clause 6 – Special provisions relating to the grant of dispensations	(1) Before granting a **dispensation**, the **system operator** must issue a draft decision on the application. The draft decision must be **published** on the **system operator register** and must include— … … (3) A **participant** may make a submission to the **system operator** on the application that resulted in the **publication** of the draft decision no later than 10 **business days** after the draft decision is recorded on the **system operator register**. …
41.	Schedule 8.3	Schedule 8.3 ~~cl 1.1~~ cls 8.25 and 8.28 Technical codes
42.	Schedule 8.3, Technical Code A, clause 7(1) – Modifications and changes to assets	(1) **Assets** that have been modified, or are proposed to be modified, are deemed to be new **assets** for the purposes of this Code and this **Technical Code** and are subject to the requirements for connection to the **grid** and the requirements for **commissioning assets**. … (c) a new connection of an **embedded generator** to a **local network** other than an ~~**excluded generator**~~ **excluded generating station** as defined in clause 8.21(1): …
43.	Schedule 8.3, Technical Code A, Appendix B, clause 1(4) – Periodic tests to be carried out	(4) Each **asset owner** with one or more **generating units commissioned** before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.
44.	Schedule 8.3, Technical Code B, clause 5A(4) – Request to inform the system operator of available controllable load	(4) If the **system operator** requests information regarding available **controllable load** under subclause (1), a **connected asset owner** who submits **difference bids** must, as soon as reasonably practicable following a request by the **system operator**— (a) submit to the **system operator** for each **trading period** notified by the **system operator** a **difference bid** that represents a reasonable estimate of the available **controllable load** which the **connected asset owner** can use to decrease its **demand**— (i) at each **conforming GXP** in the **connected asset owner's network** or at a **conforming GXP** nominated by the **system operator** and agreed with the **connected asset owner**; and

#	Clause	Decision
		…
45.	Schedule 8.3, Technical Code C, Appendix A, Table A2	**Table A2: Requirements of grid owners~~:~~** Each **grid owner** must provide the indications and measurements shown in Table A2 in respect of **assets** connected to, or forming part of, the **grid**. …
46.	10.8(1) – Requirements for information to be recorded, given, produced, or received	(1) In this Part, a **participant** who must record, give, produce, or receive information, must do so in accordance with 1 or more of the following requirements **published** or notified by the **Authority**: …
47.	10.21(1) – When metering equipment provider's obligations come into effect	(1) The obligations under this Part of a person who assumes responsibility, or is appointed to be responsible, as the **metering equipment provider**, under clauses 10.19(2) or 10.22, for a **metering installation**, commence,— (a) for an **ICP** that is not also an **NSP**, on the date that is recorded in the **registry** as being the date on which the **metering installation** equipment was installed; or …
48.	10.22(1C) – Change of metering equipment provider	(1C) If the **losing metering equipment provider** does not carry out the calculation and notify the **gaining metering equipment provider** under subclause ~~1(A)~~ (1A) within the time frame in that subclause, the **gaining metering equipment provider** does not need to comply with subclause (2).
49.	10.22(5) – Change of metering equipment provider	(5) Despite subclause (2), a **gaining metering equipment provider** is not required to pay the costs if— …
50.	10.33A(1) – When trader may electrically connect point of connection	(1) A **trader** may **electrically connect** a **point of connection**, or another **participant** authorised by a **trader** may **electrically connect** a **point of connection**, only if—… (a) for a **point of connection** that is an **ICP**, but which is not an **NSP**,— (i) either— (A) the **trader** is recorded in the **registry** as being responsible for the **ICP**; or (B) if the **ICP** has been **electrically disconnected**, the **trader**—

#	Clause	Decision
		(1) has an arrangement with a **customer** or **embedded generator** at the **ICP**; and (2) initiates a **switch** under clause 2, 9, or 14 of Schedule 11.3 within 2 **business days** of the date of **electrical connection**; and …
51.	10.33A(3) – When trader may electrically connect point of connection	(3) A **trader** must not **electrically connect** or authorise the **electrical connection** of a **point of connection** in any of the following circumstances— … (c) a **switch** described in subclause (1)(a)(i)(B)(2) has been withdrawn or reversed. …
52.	10.33A(5) – When trader may electrically connect point of connection	(5) Under subclause (1)(a)(i), if a **trader** or a person authorised by a **trader electrically connects** an **electrically disconnected point of connection** in error, or prior to the **switch** being withdrawn or reversed, the **trader** must— … (b) reimburse the losing **trader** for any direct costs the losing **trader** incurred because of the **electrical connection** of the **point of connection**— (i) in error; or (ii) prior to the **switch** being withdrawn or reversed.
53.	10.33C(5) – When trader may bridge meter at ICP	(5) If a **meter** is bridged under subclause (1), in all cases, the **trader** responsible for the **ICP** must— … (c) within 1 **business day** of being advised that the **meter** is bridged, notify the **metering equipment provider** responsible for the bridged **meter** that it is required to reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a **certified metering installation**.
54.	10.33C(6) – When trader may bridge meter at ICP	(6) The **metering equipment provider** receiving the notice under subclause (5)(c) must reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a **certified metering installation** within 5 **business days** of receiving the notice.
55.	10.37(1) – Active and reactive measuring and recording requirements	(1) A **metering equipment provider** must ensure that each **half-hour metering installation** that is a category 3 **metering installation,** or higher category of **metering installation**, **certified** after 29 August 2013, measures and separately records, in accordance with this Part …
56.	10.48(3) – Correction of	(3) A **metering equipment provider** must, within 10 **business days** of being advised under subclause (1), advise the **reconciliation participant**

#	Clause	Decision
	defects and inaccuracies in raw meter data	responsible for providing **submission information** for the **point of connection**, of the correction factors referred to in clause 10.46(1)(h) and the period referred to in clause 10.46(1)(i).
57.	Schedule 10.7, clause 6(1) – Determining metering installation incorporating current transformer to be lower category	(1) When determining the category of a **metering installation** under clause 5(a), an **ATH** may under subclause (2) determine the category of a **metering installation** to be lower than would otherwise be the case under clause 5(a) only in 1 of the following circumstances: … (c) if the **metering installation** uses less than 0.5 GWh in any 12 month period: …
58.	Schedule 10.7, clause 8A(2) – ATH amends certification reports	(2) An amendment under subclause (1) must not— (a) change the category of the **metering installation**: (b) extend the expiry date in the **certification report**: …
59.	Schedule 10.7, clause 20(1) – **Cancellation of certification of metering installations**	(1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place: … (j) the **metering installation** is a **half-hour metering installation** and was **certified** after 29 August 2013, the **services access interface** is the **metering equipment provider's back office**, and the **metering equipment provider**— …
60.	Schedule 10.7, clause 37(2) – Data storage device certification expiry date	(2) The **data storage device certification** expiry date must— (a) for a **data storage device** that is integral to a **meter**, be no later than the **meter certification** expiry date; or …
61.	Schedule 10.7, clause 41(2) – Certification stickers	(2) An **ATH** attaching a **metering installation certification sticker** must ensure that it shows— (b) the most recent **certification** date of the metering installation; and …
62.	Schedule 10.7, clause 41(7)	The combined sticker under subclause (5) is immediately invalid if— (a) the **metering installation certification** expiry date changes; or
63.	Schedule 10.7, clause 45(1A)	When inspecting a sample of **category 1 metering installations** under subclause (1)(b), the **metering equipment provider** must—

#	Clause	Decision
		… (b) perform the first inspection in the same calendar year the oldest **metering installation** reaches 84 months since **certification**.
64.	Schedule 10.7, clause 48(1A)	(1A) A **distributor** may interfere with a **metering installation** without authorisation of the **metering equipment provider** responsible for the **metering installation** to reset a load control switch contained within a load **control device** or bridge or unbridge a load control switch if— … (b) the **distributor** provides the load control signal to the load **control device**.
65.	Schedule 10.7, clause 48(1E) – Removal or breakage of seals	(1E) A **trader** may remove or break a seal in a **metering installation** without authorisation of the **metering equipment provider** responsible for the **metering installation**— (a) to **electrically connect** the load or generation measured by the **meter** if the load or generation has been **electrically disconnected** at the **meter**; or (b) to **electrically disconnect** the load or generation measured by the **meter** if the **trader** has exhausted all other appropriate methods of **electrical disconnection**; or (c) to bridge the **meter**.
66.	Schedule 10.8, clause 9(1) – Onsite calibration and certification	(1) A **certifying ATH** may only **calibrate** a **metering component** onsite— … (b) by— … (ii) ensuring that— (A) the effects of any departures from the reference conditions specified in the relevant standards listed in Table 5 of Schedule 10.1 can accurately and reliably be calculated; and …
67.	11.1 – Contents of this Part	This Part— … (f) requires **retailers** to give **consumers** their **electricity** information ~~about their own consumption of **electricity**~~; and …

#	Clause	Decision
68.	11.26 – Reports to reconciliation manager	By 1600 hours on the 4th **business day** of each calendar month… the **registry manager** must deliver the following reports to the **reconciliation manager**: (a) a report identifying the number of **ICP days** per **NSP**, differentiated by **half-hour metering** type or **non** **half-hour metering** type (for the purpose of this clause, **half-hour metering** type on the **registry** must be reported as **half hour**, and all other metering types must be reported as non **half hour**) attributable to each **trader** for those **NSPs** that are recorded on the **registry** as consuming **electricity** at any time during, as the case may be, that **consumption period** or any of those **consumption periods**: …
68A.	11.30B(5) – information on plan comparison site	(5) If the **Authority** changes the web address of the electricity plan comparison website, establishes a new platform to perform the same purpose, or changes that platform or its location descriptor, each **retailer** must change the information published or provided under clause 11.30~~A~~B to refer to the new address, platform or location descriptor as soon as reasonably possible and no later than 3 months from the date the change is notified on the **Authority's** website.
69.	Schedule 11.1, clause 1(3) – ICP identifiers	(3) Despite any clause to the contrary, only the obligations in this clause and clauses 2, 6 and 7(1)(a) to (e), (l) and (m) apply if an **ICP identifier** is used to identify a— (a) **point of connection** between an **embedded network** and its parent **network**; or (b) **point of connection** between **shared unmetered load** and its **network**.
70.	Schedule 11.1, clause 5 – Electrical load	The electrical load associated with an **ICP** is deemed to be supplied through 1 ~~**network supply point**~~ **NSP** only.
71.	Schedule 11.1, clause 11(1) – Correction of errors in the registry	(1) By 0900 hours on the 1st **business day** of each **reconciliation period**, the **registry manager** must provide to each **participant** who is required to submit **submission information**, the following: (a) a list of the **ICPs** at which the **participant** is recorded on the **registry** as trading during each **consumption period** being revised in the **reconciliation period**: …
72.	Schedule 11.1, clause 19(2) –	(2) The **ICP** status of "Inactive" may be managed by the relevant **distributor** only to indicate that— …

#	Clause	Decision
	"Inactive" status	(b) the **ICP** cannot be **electrically disconnected** following a request for **electrical disconnection**.
73.	Schedule 11.1, clause 25(5) – Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network	(5) The **participant** required to give notice under subclause (1) must give notice no later than 30 days prior to the intended date of creation or **decommissioning** of the **NSP**.
74.	Schedule 11.3, clause 4(1) – Event dates	(1) The losing **trader** must establish **event dates** so that— (a) no **event date** is more than 10 **business days** after the date on which the **registry manager**, under clause 22(a), makes written notice available to the losing **trader**; and …
75.	Schedule 11.3, clause 13 – Gaining trader switch processes	(1) A gaining **trader** switch process applies only when a **trader** (the "gaining **trader**") has an arrangement with a customer or **embedded generator** to— (a) trade **electricity** with the customer or **embedded generator** at an **ICP** at which another **trader** (the "losing **trader**") trades **electricity** with the customer or **embedded generator**, and one of subparagraphs (i) to (iii) applies— … (ii) at the **ICP**— …
76.	Schedule 11A.1, clause 36(3) – Disconnection of uncontracted premises	(3) The notices required under subclauses (1)(b) and (1)(c): (a) may be provided in the same notice or in separate notices at different times; (b) must be in writing and delivered to the ~~**uncontacted**~~ **uncontracted premises**; and (c) must include information about how to contact the **retailer** to discuss signing up as a new **customer**.
77.	12.10(3) – Default transmission agreements	(3) The service levels set out in Schedule 5 of a **default transmission agreement** must be determined on the following basis: …

#	Clause	Decision
		(b) the service levels for the voltage range specified in the capacity service measures for each **branch** must be consistent with,— … (ii) for **assets** of voltages less than 50kV, the normal operating voltage of the component **assets**: …
78.	12.50 – Copies of other agreements to be provided to Authority	If requested to do so by the **Authority**, **Transpower** or a **participant** must provide a copy of any written agreement for connection to and/or use of the **grid** that **Transpower** or the **participant** is a party to and that was entered into before 28 June 2007, including any amendments.
79.	12.57 – Principles of grid reliability standards	The **grid reliability standards** should— (a) take into account that transmission investments are long-lived **assets** and require a long-term planning perspective; and (b) reflect the public interest in reasonable stability in planning, having regard to the long term nature of investment in transmission **assets**; and …
80.	12.77 – Recovery of investment costs by Transpower	The costs incurred by **Transpower** (irrespective of when they are incurred) in relation to an **approved investment** are recoverable by **Transpower** from **designated transmission customers** on the basis of the **transmission pricing methodology** and must be paid by **designated transmission customers** accordingly.
81.	12.110(1) – Incorporation of interconnection asset capacity and grid configuration by reference	(1) The **interconnection asset** capacity and **grid** configuration is incorporated by reference in this Code. …
82.	12.114(1) – Investments to met the grid reliability standards	(1) If a **grid reliability report** identifies, in accordance with clause 12.76(1)(c), that the power system is not reasonably expected to meet the **N-1 criterion** at a **grid exit point** at all times over the 5 years following the date on which the report is **published** and that this is due to an **interconnection asset**, **Transpower** must— … (b) if the **interconnection asset** does not meet the **grid reliability standards**, consider reasonably practicable options for ensuring that the

#	Clause	Decision
		grid reliability standards can be met in respect of that **interconnection asset**; and …
83.	12.117 – Permanent removal of interconnection assets from service or permanent grid reconfiguration	… (2) When **Transpower** is required to apply a net benefit test, **Transpower** must— (a) estimate the following costs: … (iii) any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**: … (b) estimate the following benefits: … (iii) any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**: … (9) The estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy** under subclause (2) must be based on the value of **expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer. …
84.	12.127(1) – Transpower to report on availability and reliability	(1) By 30 November in each year, **Transpower** must **publish** and provide to the **Authority** information on availability and reliability of **interconnection assets** including— … (i) a comparison of the information required by paragraphs (a) to (f) against the availability and reliability index measures for **interconnection branches**, **shunt assets** and the **HVDC link** included in a schedule to this Part under clause 12.126; and …
85.	12.141(2) – Consideration of likely effects	(2) The requirements in subclause (1) that the **Outage Protocol** may provide are—

#	Clause	Decision
	of planned outages	(a) if a proposed **planned outage** is likely to result in the power system failing to meet the **grid reliability standards**, but is not expected to give rise to **binding constraints** or result in loss of **supply** to **consumers**, **Transpower** must— (i) estimate the following costs: … (C) if the **outage** will result in an increased risk of loss of **supply**, any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (ii) estimate the following benefits: (A) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (b) if a proposed **planned outage** is likely to give rise to **binding constraints**, whether or not the **outage** is also likely to result in a loss of **supply** to **consumers**, **Transpower** must— (i) estimate the following costs: … (C) if the **outage** will result in an increased risk of loss of **supply**, any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (ii) estimate the following benefits: (BA) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (c) if a proposed **planned outage** is likely to lead to loss of **supply** to **consumers**, whether or not the **outage** is also likely to give rise to **binding constraints**, **Transpower** must— (i) estimate the following costs: … (C) any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising from the loss of **supply** during the **outage**: …

#	Clause	Decision
		(ii) estimate the following benefits: … (B) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: …
86.	12.141(3) – Consideration of likely effects of planned outages	(3) In providing for the matters referred to in subclause (2), the **Outage Protocol** must include the following requirements: … (d) the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy** under subclause (2) must— …
87.	Schedule 12.3, clause 2(2)	(2) The **core grid** consists of those **assets** that comprise the transmission links listed in Table 1 below: …
88.	Schedule 12.4, clause 3 – definition of **capacity**	**capacity** means the rated capacity of an asset to (as the case may be)— (a) consume or generate **electricity**; or (b) take **electricity** from or inject **electricity** into a **network**; or (c) transmit or distribute **electricity**, in each case measured in units appropriate for the context
89.	Schedule 12.4, clause 3 – definition of **injection**	**injection** means— (a) for a **trading period** and a **customer's grid point of connection**, the positive net quantity of **electricity** flow into the **grid** at the ~~**grid point of injection**~~ ~~**grid injection point**~~ **grid point of connection** from the **customer's** assets during the **trading period** (if any); and …
~~90.~~	~~Schedule 12.4, clause 3 – definition of~~	~~(2) In this **transmission pricing methodology**, words and phrases appear in bold to alert the reader to the fact that they are defined in this clause or clause 1.1.~~
91.	Schedule 12.4, clause 20(4) – Connection and Interconnection Nodes and Links	(4) If a group of **nodes** or **links** that are to be provided as part of the same project are **commissioned** in a staged manner, the connection or interconnection status of each **node** and **link** in the group must be determined prospectively based on all **nodes** and **links** in the group being **commissioned**. However— …

#	Clause	Decision
92.	Schedule 12.4, clause 24(4) – Calculation of Connection Charges	Current: $TACC = TAC \times \frac{\sum_l ACC_l}{\sum_l ACC_{l\ total}}$
		Updated: $TACC = TAC \times \frac{\sum\limits_l ACC_l}{\sum\limits_l ACC_{l\ total}}$
93.	Schedule 12.4, clause 51(6) – Calculation of Market Regional NPB based on Quantity	Current: $MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$
		Updated: $MRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (EMBD_s \times W_s)$
94.	Schedule 12.4, clause 52(8) – Calculation of Market Regional NPB based on Price and Quantity	Current: $MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$
		Updated: $MRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (EMBD_s \times W_s)$

#	Clause	Decision
95.	Schedule 12.4, clause 53(6) – Ancillary Service Regional NPB	Current: $$ASRNPB = \frac{1}{\sum_s W_s} \sum_s (EASBD_s \times W_s)$$
		Updated: $$ASRNPB = \frac{1}{\sum_s W_s} \sum_s (EASBD_s \times W_s)$$
96.	Schedule 12.4, clause 54(7) – Reliability Regional NPB	Current: $$RRNPB = \frac{1}{\sum_s W_s} \sum_s (ERBD_s \times W_s)$$
		Updated: $$RRNPB = \frac{1}{\sum_s W_s} \sum_s (ERBD_s \times W_s)$$
97.	Schedule 12.4, clause 64(2) – Regional NPB	Current: $$RNPB = \frac{1}{\sum_t W_t} \sum_t (SMC_t \times W_t) \times F$$
		Updated: $$RNPB = \frac{1}{\sum_t W_t} \sum_t (SMC_t \times W_t) \times F$$

<table>
<tr><th>#</th><th>Clause</th><th>Decision</th></tr>
<tr><td>98.</td><td>Schedule 12.4, clause 64(5) –
Regional NPB</td><td>Current:
<table>
<tr><th>connection region A</th><th>connection region B</th><th>connection region C</th></tr>
<tr><td>$\frac{G_a}{(G_a + L_a + F_{a\_b})}$</td><td>$\frac{F_{a\_b}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$</td><td>$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{F_{a\_b}}{G_b + F_{a\_b}}\right)$</td></tr>
<tr><td>0</td><td>$\frac{G_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$</td><td>$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{G_b}{G_b + F_{a\_b}}\right)$</td></tr>
<tr><td>0</td><td>0</td><td>$\frac{G_c}{(G_c + L_c + F_{b\_c})}$</td></tr>
<tr><td>$\frac{L_a}{(G_a + L_a + F_{a\_b})}$</td><td>0</td><td>0</td></tr>
<tr><td>$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{L_b}{L_b + F_{b\_c}}\right)$</td><td>$\frac{L_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$</td><td>0</td></tr>
<tr><td>$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{F_{b\_c}}{L_b + F_{b\_c}}\right)$</td><td>$\frac{F_{b\_c}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$</td><td>$\frac{L_c}{(G_c + L_c + F_{b\_c})}$</td></tr>
</table>
Updated:
<table>
<tr><th>connection region A</th><th>connection region B</th><th>connection region C</th></tr>
<tr><td>$\frac{G_a}{(G_a+L_a+F_{a_b})}$</td><td>$\frac{F_{a_b}}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{F_{b_c}}{(G_c+L_c+F_{b_c})}(\frac{F_{a_b}}{G_b+F_{a_b}})$</td></tr>
<tr><td>0</td><td>$\frac{G_b}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{F_{b_c}}{(G_c+L_c+F_{b_c})}(\frac{G_b}{G_b+F_{a_b}})$</td></tr>
<tr><td>0</td><td>0</td><td>$\frac{G_c}{(G_c+L_c+F_{b_c})}$</td></tr>
<tr><td>$\frac{L_a}{(G_a+L_a+F_{a_b})}$</td><td>0</td><td>0</td></tr>
<tr><td>$\frac{F_{a_b}}{(G_a+L_a+F_{a_b})}(\frac{L_b}{L_b+F_{b_c}})$</td><td>$\frac{L_b}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>0</td></tr>
<tr><td>$\frac{F_{a_b}}{(G_a+L_a+F_{a_b})}(\frac{F_{b_c}}{L_b+F_{b_c}})$</td><td>$\frac{F_{b_c}}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{L_c}{(G_c+L_c+F_{b_c})}$</td></tr>
</table></td></tr>
<tr><td>99.</td><td>Schedule 12.4, clause 83(5) – Benefit-based Charge Adjustment Event: New Customer</td><td>(5) The following tables illustrate the application of subclause (3) to a new customer (customer E) entering regional customer group Y for a post-2019 BBI under the price-quantity method where regional customer group Y is not a future regional customer group:
…
After (paragraph (3)(d))</td></tr>
<tr><td>100.</td><td>Schedule 12.4, clause 83(5C) –Benefit-based Charge Adjustment</td><td>(5C) If this subclause applies under subclause (5A), Transpower must, instead of applying the new customer's benefit-based charges for the relevant post-2019 BBIs under the simple method calculated under subclause (3)—</td></tr>
</table>

#	Clause	Decision
	Event: New Customer	(a) attribute part of the new **customer's simple method BBC cap** to each **investment region** in respect of which the relevant **regional customer group** has positive **regional NPB** as follows: … where $SMBC_{region}$ is the part of the new **customer's simple method BBC cap** attributed to the **investment region** **…** (b) calculate the new **customer's BBI customer allocation** for each relevant **post-2019 BBI** (CA) as follows: $$CA = \frac{SMBC_{region}}{CC_{region\ total}}$$ where $SMBC_{region}$ is the part of the new **customer's ~~simple method benefit cap~~ simple method BBC cap** attributed to the **investment region** in which the relevant **post-2019 BBI** is located under paragraph (a) …
101.	Schedule 12.4, clause 88(3) – Benefit-based Charge Adjustment Event: Changed Point of Connection	(3) If the notional new **customer's BBI customer allocation** for a relevant **BBI** is equal to or more than the notional exiting **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must— (a) apply paragraph 85(2)(b) for the connecting **customer** and relevant **BBI**; and …
102.	Schedule 12.4, clause 112(2) – Cap Recovery Charge	(2) A **customer's annual cap recovery charge** for a **pricing year** (ACRC) is calculated as follows: … $CRRC_{total}$ is the total of all **customers**' **cap recovery-relevant charges** for the **pricing year**, excluding **~~cap recovery relevant charges~~ cap recovery-relevant charges** for **customers** who receive a **cap reduction** for the **pricing year**.
103.	Schedule 12.4, clause 117(2) – Calculation of Alternative Project Costs	(2) For the purposes of calculating the **alternative project costs**— (a) the value of any increase or decrease in electrical losses that would result from the **alternative project** must be included as an operating cost of the **alternative project** (with a decrease being treated as a negative cost); and …
104.	Schedule 12.4, clause 122(3) – Calculation	(3) If a **back-dated prudent discount** is not reflected in the **transmission charges** for the **back-dated prudent discount's start**

#	Clause	Decision
	of Back-dated Prudent Discounts	**pricing year** or any later **pricing year** during the term of the relevant **prudent discount** agreement (a relevant **pricing year**), **Transpower** must carry out a wash-up of the **prudent discount recipient's transmission charges** for each relevant **pricing year** so that the **prudent discount recipient** is not over-charged **transmission charges** for the relevant **pricing years**. The wash-up— …
105.	Schedule 12.4, clause 123 – Calculation of Annuity	Current: $AN = \frac{PVAPC}{\sum_{n=1}^{N} \frac{1}{(1+r)^n}}$
		Updated: $AN = \frac{PVAPC}{\sum_{n=1}^{N} \frac{1}{(1+r)^n}}$
106.	Schedule 12.4, clause 133 – Purpose of Stand-alone Cost Prudent Discount	The purpose of a **stand-alone cost prudent discount** is to help ensure this **transmission pricing methodology** does not result in a **customer** paying **transmission charges** that exceed the efficient stand-alone cost of the **transmission services** the **customer** currently receives. A **stand-alone cost prudent discount** achieves this by replacing the **prudent discount recipient's connection charges**, **benefit-based charges** and **residual charge** with an annuity under a **prudent discount** agreement equal to the **alternative project costs** of an **efficient stand-alone investment**.
107.	Schedule 12.6, clause 37.2 – Real time signal of demand by Region from SCADA	Transpower must provide to the Customer information on the ~~**regional demand**~~ ~~regional demand~~ regional **demand** (as calculated under~~defined in~~ the **transmission pricing methodology**) for each region that the Customer has a **connection location**. This information is to be derived from **SCADA**, updated at least every five minutes, and updated not more than five minutes after the ~~**regional demand**~~ ~~regional demand~~ regional **demand** is measured.
108.	13.2E(1) – Publication of information in quarterly disclosure reports by the Authority	(1) The **Authority** may **publish** any information submitted to it in a **quarterly disclosure report**, the certification required by clause 13.2D(1)(a) and the report required by clause 13.2D(1)(b), provided any such **publication** does not involve the **publication** of— …

#	Clause	Decision
109.	13.2G – Authority may require review of disclosure requirements or certification by independent person	~~(1)~~ The **Authority** may, in its discretion, require a review by an independent person of whether a **major participant** may not have complied with any or all of clauses 13.2B to 13.2D.
110.	13.3A(5) – Approval process for dispatch-capable load stations	(5) Where the **system operator** suspends such an approval under subclause (4), the **system operator** must continue such suspension until— (a) the **purchaser** re-commences operating as a **dispatch notification purchaser** in respect of the relevant **dispatch-capable load station**; or
111.	13.3E(3) – Approval process for dispatch notification purchasers	(3) If the **system operator** approves a **purchaser's** application to become a **dispatch notification purchaser**,— … (c) the **purchaser** in respect of which approval is granted is not a **dispatch notification purchaser** while approval for the relevant **dispatch-capable load station** is suspended under clause 10 of Schedule 13.8.
112.	13.4 – Contents of this subpart	This subpart provides for processes to facilitate trading by which— …
113.	13.6 – Requirements for generators when submitting offers	(1) Each **generator** with a **point of connection** to the **grid**, and each **embedded generator** required by the **system operator** to submit an **offer** under clause 8.25(5), must— (a) for a **generator** other than an **intermittent generator**~~;~~: … (b) subject to subclause (2), for an **intermittent generator**~~;~~: …
114.	13.9B(3) – Offer requirements for intermittent generators	(3) If clause 13.6(1)(b)~~(ii)~~(iii) applies, each **forecast of generation potential** must use either: (a) the long-term seasonal average for that time of year for that **intermittent generating station** and **trading period**: or …
115.	13.9C – Information must be	An **intermittent generator** required to use an **approved forecast** under subclause (2) must, in response to a request from the ~~**approved forecaster**~~ **approved forecast provider**, provide any information

#	Clause	Decision
	provided in response to an approved forecaster request	reasonably required by the ~~**approved forecaster**~~ **approved forecast provider** for the purpose of providing an **approved forecast**, as soon as practicable after receiving the request.
116.	13.19C(4) – Dispatch notification purchasers and dispatch notification generators to submit revised bids and offers in certain circumstances	(4) A **dispatch notification generator** that submits a revised **offer** under this clause— (a) is deemed to have submitted an **offer** in which the **MW** specified in the **offer** is 0 for the **trading period** following the **trading period** to which the revised **offer** relates; and …
117.	13.82(2)	(2) Each **participant** to which this clause applies must comply with a **dispatch instruction** properly issued by the **system operator** under clause 13.72(1)(a) unless,—… (b) the **generating plant** or **dispatch-capable load station** is already responding to an automated signal to activate— (i) ~~**capacity reserve**; or~~ *[Revoked]* (ii) **instantaneous reserve**; or (iii) **automatic under-frequency load shedding**; or (iv) **over frequency reserve**; or …
118.	13.98 – Generators and ancillary service agents may change other parameters	Despite clause 13.97(2), during a **grid emergency**,— … (c) despite clauses 13.6 to 13.27, a **generator** may— (i) submit revised **offers** in respect of **generating plant** already subject to an **offer** before the **grid emergency**, so that the total **MW** offered by the **generator** from the **generating plant** for that **trading period** is increased; and …
119.	13.136(1A) – Offered embedded generators to provide half-	(1A) For the purposes of subclause (1), the relevant **grid owner** is— (a) in relation to a **generator** (other than an **embedded generator**), the **grid owner** of the **grid** to which the **generator's** generation is connected; and

#	Clause	Decision
	hour metering information	…
120.	13.173C – Authority to determine whether pricing error has occurred	(2) The **Authority** must, as soon as practicable after making its determination,— … (b) give a written notice on **WITS** that includes the following information: (i) the name of the error claimant (where a **pricing error** has been claimed): …
121.	13.219(1) – Information that must be submitted	(1) The **party** specified in clause 13.218 must submit the following information to the **approved system** in relation to every **risk management contract**, excluding exchange-traded **risk management contracts** where the **parties** have provided consent under clause 13.236AA: …
122.	13.205 – Calculation of constrained on amounts attributable to system operator	If a **constrained on situation** occurs during a **trading period** in a previous **billing period**, and the **clearing manager** receives notice of the **constrained on situation** under clause 13.76, the **clearing manager** must determine the portion of the **constrained on amounts** calculated under clause 13.204 attributable to the **system operator** for each **generator** or each **ancillary service agent** as follows: … (b) if the **system operator** has advised the **clearing manager** that a non-security **constrained on situation** occurred the **system operator** must be allocated a **constrained on amount** calculated in accordance with the following formula: … TCONP is the total constrained on payment for that **trading period** …
123.	13.231A – Audit process	… (4) Before the **audit** report is submitted to the **Authority**, the **auditor** must refer any apparent failure by the **participant** to comply with this subpart that the **auditor** has identified to the **participant** for comment within the timeframe specified by the **auditor**. (5) The **audit** report must include any comments from the **participant** on any apparent non-compliance that the **auditor** referred to the

#	Clause	Decision
		participant under subclause (4) if the **participant** provided comments to the **auditor** within the time specified by the **auditor**. …
124.	13.233(1) – WITS manager and Authority must keep certain information confidential	(1) The **Authority** must keep, and ensure that the **WITS manager** keeps, information submitted to the **approved system** under this subpart confidential, unless— (a) the information is provided by the **Authority** to subcontractors or service providers that the **Authority** appoints to provide services for the purposes of this subpart, and those subcontractors or service providers have agreed to keep that information confidential, on the same terms as apply to the **Authority** under this clause; or …
125.	13.236A – Disclosing participants must prepare and submit spot price risk disclosure statements	(4) A **participant** is not required to comply with this clause for a quarter if it is a **disclosing participant** in relation to the quarter only because it is subject to a ~~**wash-up**~~ **washup** in that quarter.
126.	13.256(3) – Generator retailers must provide ITP information to the Authority	(3) The information provided by a **generator retailer** under subclause (2)(b) must include the following: (a) a breakdown of the key components or factors which make up the **retail ITP** expressed as an amount in dollars and cents per **MWh** that each key component or factor comprises of the average load weighted **retail ITP** required by subclause (2)(a), and which must include (if relevant) the following components or factors: … (ii) the distribution of the total electrical load across locations, including the adjustment, calculated on an average load weighted basis in **MWh**, that the ~~**retailer** generator~~ **generator retailer** used to determine the **retail ITP** for the **electricity** sold to **mass market customers** beyond a **node** specified in an **ASX NZ electricity future**: …
127.	13.258 – Publication of ITP information by the Authority	The **Authority** may **publish** any **ITP information** or information submitted to it under clause 13.257, as the **Authority** sees fit.
128.	13.279 – Appointment of auditor	(1) The **Authority** may, in its discretion, carry out an **audit** as to whether a **generator** has complied with this subpart.

#	Clause	Decision
		(2) If the **Authority** decides under subclause (1) that a **generator** should be subject to an audit— (a) the **Authority** must require the **generator** to nominate an appropriate **auditor**; and (b) the **generator** must provide that nomination to the **Authority** within a reasonable timeframe. (3) The **Authority** may appoint the **auditor** nominated by the **generator** or a different **auditor**, having regard to any factors it considers relevant in the circumstances, including— (a) the expected quality of the **audit**: (b) the expected costs of the **audit**. (4) If the **generator** fails to nominate an appropriate **auditor** within 20 **business days**, the **Authority** may appoint an **auditor** of its own choice.
129.	13.280 – Carrying out of audit	(1) A **generator** subject to an **audit** under clause 13.279 must, on request from the **auditor**, provide the **auditor** with such information as the **auditor** reasonably requires in order to carry out the **audit**. (2) The **generator** must provide the information no later than 20 **business days** after receiving a request from the **auditor** for the information. (3) The **generator** must ensure that the auditor provides the **Authority** with an **audit** report on the **generator's** compliance with this subpart within the timeframe specified by the **Authority**. (4) The **audit** report must include any other information the **Authority** may reasonably require. (5) Before the **audit** report is provided to the **Authority**, any identified failure of the **generator** to comply with this subpart must be referred back to the **generator** for comment. (6) The comments of the **generator** must be included in the **audit** report. (7) The **audit** report must not contain any contract that the **generator** has provided to the **auditor** unless the contract meets the definition of a **materially large contract**.
130.	13.281 – Payment of costs relating to audits	(1) If an **audit** establishes, to the reasonable satisfaction of the **Authority**, that a **generator** may not have complied with this subpart (whether or not the **Authority** appoints an investigator to investigate the alleged breach), the **generator** must pay for the **audit**. (2) If the **Authority** considers that the non-compliance of the **generator** is minor or there is any other reason in the **Authority's** view that means the **generator** should not pay the costs of the **audit**, the **Authority** may, in its discretion, determine the proportion of the costs of the **audit** that are to be paid by the **generator**, and those costs must be paid by the

#	Clause	Decision
		generator with any remaining proportion of costs paid by the **Authority**. (3) If an **audit** establishes to the reasonable satisfaction of the **Authority** that the **generator** has complied with this subpart, the **generator** is not required to pay any of the **auditor's** costs and the **Authority** will pay the **auditor's** costs.
131.	Schedule 13.3, clause 8(1) – The objective function	Current: Maximise $\left\{ \overbrace{\sum_{i,j} D_{i,j} \times BP_{i,j}}^{\text{Gross Consumer Benefit}} \text{ minus } \overbrace{\sum_{i,j} G_{i,j} \times OP_{i,j}}^{\text{Cost of Generation}} \text{ minus } \overbrace{\sum_{i,j} R_{i,j}^{GR,f} \times OP_{i,j}^{GR,f} + \sum_{i,j} R_{i,j}^{IL,f} \times OP_{i,j}^{IL,f}}^{\text{Cost of Fast Instantaneous Reserves}} \text{ minus } \overbrace{\sum_{i,j} R_{i,j}^{GR,s} \times OP_{i,j}^{GR,s} + \sum_{i,j} R_{i,j}^{IL,s} \times OP_{i,j}^{IL,s}}^{\text{Cost of Sustained Instantaneous Reserves}} \right\}$
		Updated: Maximize $\left\{ \overbrace{\sum_{i,j} D_{i,j} \times BP_{i,j}}^{\text{Gross Consumer Benefit}} \text{ minus } \overbrace{\sum_{i,j} G_{i,j} \times OP_{i,j}}^{\text{Cost of Generation}} \text{ minus } \overbrace{\sum_{i,j} R_{i,j}^{GR,f} \times OP_{i,j}^{GR,f} + \sum_{i,j} R_{i,j}^{IL,f} \times OP_{i,j}^{IL,f}}^{\text{Cost of Fast Instantaneous Reserves}} \text{ minus } \overbrace{\sum_{i,j} R_{i,j}^{GR,s} \times OP_{i,j}^{GR,s} + \sum_{i,j} R_{i,j}^{IL,s} \times OP_{i,j}^{IL,s}}^{\text{Cost of Sustained Instantaneous Reserves}} \right\}$
132.	Schedule 13.3, clause 9 – Constraints	In maximising the objective function, the **system operator** must ensure that the following constraints are met to an accuracy specified in the **model formulation**: … (b) each constraint relating to generation set out in clause 9A: …

#	Clause	Decision
133.	Schedule 13.3, clause 9A – Constraints relating to generation	The constraints for the purpose of clause 9(b) are that— … (c) the modelling system schedules **electricity** generation for each **intermittent generating station** in a **trading period** at a level that is no higher than the potential output of the **intermittent generating station**, determined as follows: (i) in relation to the **price-responsive schedule**, in accordance with clause 13.58A(1)(aa): (ii) in relation to the **non-response schedule**, in accordance with clause 13.58A(2)(aa): (iii) in relation to the **dispatch schedule**, in accordance with clause 13.71(3): (iv) ~~in relation to the **input information** referred to in clause 13.141, in accordance with clause 13.141(1)(caa):~~ *[Revoked]* (v) *[Revoked]*
134.	Schedule 13.3, clause 16(1) – Calculation of prices, marginal location factors and reserve prices	(1) The modelling system must calculate the following set of prices: … (b) reserve prices for each **island**: …
135.	Schedule 13.3AA, clause 3(1) – Adjusting expected profile of demand for demand that was unable to be supplied	(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3, **Technical Code** B, clause 6(1)(d) or 6(2)(d), the **system operator** must— …
136.	Schedule 13.4, clause 9(2) – Decision must be recorded	(2) The register must state, for each approval on the register,— (a) whether the applicant's **generating units** have been approved as a **type A industrial co-generating station** or a **type B industrial co-generating station**; and …
137.	Schedule 13.4, clause 13(2) – Authority may	(2) The **Authority** may, at the request of a **type A co-generator** or a **type B co-generator**, amend an approval to change a **type A industrial**

#	Clause	Decision
	rescind or amend approval	**co-generating station** to a **type B industrial co-generating station**, or vice-versa.
138.	Schedule 13.5, clause 2(2) – Requirements for design of FTRs	(2) At a minimum, the **FTRs** allocated under the **FTR allocation plan** must be **FTRs** between a **hub** in the South Island and a **hub** in the North Island that would provide a reasonable match with the trading points for exchange–traded futures products or the equivalent **electricity** futures products, and which would enable the volumes of **FTRs** available to reflect inter-**island grid** capacity.
139.	Schedule 13.8	**Schedule 13.8** **cls 1.1, 13.3A, 13.3B and 13.3E** **Approval of dispatch-capable load station**
140.	15.13 – Notice by embedded generators	An **embedded generator** must give a notice to the **reconciliation manager** for an **embedded generating station** in relation to a **point of connection** for the purposes of clauses 15.3 and 15.5(3) if the **embedded generator** will not receive payment from the **clearing manager** or any other person for any **electricity** generated by the relevant ~~**embedded generation station**~~ **embedded generating station** through the **point of connection** to which the notice relates.
141.	15.26 – Reconciliation manager to correct information	… (2) If the **reconciliation manager** considers that information provided by a **reconciliation participant** or a service provider under this Part is incorrect, the **reconciliation manager** must refer the issue to the **Authority**, and, if directed by the **Authority** to do so, take all reasonable steps to correct the information. (3) A **reconciliation participant** or service provider must provide any information to the **reconciliation manager** that the **reconciliation manager** requires to correct information under subclause (2). …
142.	Schedule 15.2, clause 11(2)	(2) **Raw meter data** obtained by the electronic **interrogation** of a **metering installation** must consist of the following as a minimum: … (e) for all **metering information**, an **interrogation** log generated by the **interrogation** software to record details of all **interrogations**. The **reconciliation participant** responsible for collecting the data must peruse the **interrogation** log and take appropriate action if problems are

#	Clause	Decision
		apparent. Alternatively, this process may be an automated software function that flags exceptions. …
143.	Schedule 15.2, clause 20 – Data transmission	Transmissions and transfers of data related to **metering** between **reconciliation participants** or **reconciliation participant's** agents, for the purposes of this Code, must be carried out electronically, using systems that ensure the security and integrity of the data transmitted and received.
143A.	Schedule 15.3, clause 8(2) – Provision of submission information to reconciliation manager	(2) For each **half-hour metering installation** for which it is responsible that is a **category 1 metering installation** or **category 2 metering installation**, a **reconciliation participant** must provide to the **reconciliation manager**— (a) **half hour submission information**; or (b) non **half hour submission information** if clause 2(1)(ad) applies; or (c) a combination of **half hour submission information** and non **half hour submission information** if— (i) the half-hour metering installation contains a combination of **half-hour metering** and **non half-hour metering**; and (ii) clause 2(1)(ae) of this Schedule 15.3 applies.
144.	Schedule 15.3, clause 8(4) – Provision of submission information to reconciliation manager	(4) However, a **reconciliation participant** need not comply with subclause (2) and subclause (3) if— … (b) the approved **profile** allows the **reconciliation participant** to provide **half hour submission information** from a **non half-hour metering installation**; and …
145.	Schedule 15.4, clause 19 - Calculation of unaccounted for electricity	Current: $AF_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{sum(SC_{R1} \times MS_{R1}, ..., SC_{Rn} \times MS_{Rn})}$ $MS_{Ri} = Q_{ICPD\text{-}LA\ Ri} / sum(Q_{ICPD\text{-}LA\ 1}, ..., Q_{ICPD\text{-}LA\ n})$

#	Clause	Decision
		Updated: $$AF_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{\sum_{i=1}^{n} SC_{Ri} \times MS_{R_i}}$$ $$MS_{Ri} = \frac{Q_{ICPD-LA\ Ri}}{\sum_{i=1}^{n} Q_{ICPD-LA\ Ri}}$$
146.	Schedule 15.4, clause 22(b) - Balancing	Current: $$Q_{BAL\ NSPx\ Ri} = \frac{Q_{ILUN\ NSPx\ Ri} \times TOT_{ND\ NSPx}}{sum(Q_{ILUN\ NSPx\ R1}, \ldots, Q_{ILUN\ NSPx\ Rn})}$$
		Updated: $$Q_{BAL\ NSPx\ Ri} = \frac{Q_{ILUN\ NSPx\ Ri} \times TOT_{ND\ NSPx}}{\sum_{i=1}^{n} Q_{ILUN\ NSPx\ Ri}}$$
147.	16A.16 – Costs of audits	… (3) If an **audit** establishes, to the reasonable satisfaction of the **Authority**, that the **participant** that was the subject of the **audit** ~~has~~ may have breached the relevant provisions of this Code (whether or not the **Authority** appoints an investigator to investigate the alleged breach), the cost of the **audit** must be met by,— (a) in respect of an **audit** carried out as a result of the **Authority** initiating the **audit**, the **participant** that was the subject of the **audit** and the **Authority**, in proportions to be determined by the **Authority**: (b) in respect of an **audit** carried out in response to a request to the **Authority** under clause 10.17B(2), 11.11(2), or 15.37C(2), the **participant** that was the subject of the **audit** and the **participant** that requested the **audit**, in proportions to be determined by the **Authority**. (4) If the **audit** establishes, to the reasonable satisfaction of the **Authority**, that the **participant** that was the subject of the **audit** ~~has not~~ does not appear to have breached the relevant provisions of this Code, or if there ~~was~~ may have been a breach but the **Authority** considers it to be minor, the cost of the **audit** must be met by,— (a) in respect of an **audit** carried out as a result of the **Authority** initiating the **audit**, the **Authority**: (b) in respect of an **audit** carried out in response to a request to the **Authority** under clause 10.17B(2), 11.11(2), or 15.37C(2), the

#	Clause	Decision
		participant that was the subject of the **audit** and the **participant** that requested the **audit**, in proportions to be determined by the **Authority**. …