Promoting reliable electricity supply: Frequency-related Code amendment proposals

Consultation paper

6 May 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the future security and resilience of New Zealand's power system in a highly electrified future, ensuring it is set up to deliver the best possible outcomes for consumers. To help achieve this, we are proactively refining industry rules to support greater electrification while maintaining a stable and reliable power system for decades to come. As the sector evolves, it is critical that we, as a regulator, anticipate challenges and enable a smooth transition to a more electrified economy.

Through our multi-year Future Security and Resilience (FSR) programme, we are taking a forward-looking approach by enabling new technologies, addressing security and resilience risks and building a power system that is reliable, flexible and future focused.

A critical part of this programme is a review of the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). These requirements are foundational to the safe and reliable supply of electricity to consumers.

We are consulting on proposed Code amendments to help address the first of seven key issues identified in the review:[1]

> **Issue 1:** An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the 'normal band' of 49.8–50.2 Hertz (Hz), which is likely to be exacerbated over time by decreasing system inertia.

This paper follows on from our consultation paper *Addressing more frequency variability in New Zealand's power system*,[2] published on 25 June 2024, which set out short-listed options to address the frequency issue. After considering submitter feedback on that paper and undertaking further investigation and analysis, the Authority proposes to amend the Code to:

- Lower the 30 megawatt (MW) threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations and technical codes in Part 8 of the Code.
- Set a permitted maximum dead band beyond which a generating station must contribute to frequency management and frequency support.

The proposed changes will promote the reliability of electricity supply and the efficient operation of the electricity industry, for the long-term benefit of consumers. These changes will enhance the reliability of electricity supply by improving frequency stability and reducing the risk of inadvertently tripping an automatic under-frequency load shedding block. The changes will promote the efficient operation of the electricity industry by minimising the need for additional reserves and frequency keeping to be procured. This will help to keep power bills lower for consumers.

1 Review of common quality requirements in Part 8 of the Code – Issues paper.

2 Addressing more frequency variability in New Zealand's power system.

We welcome your feedback

The Authority welcomes feedback on the Code amendment proposals in this consultation paper. During the consultation period Authority staff will be available to hold individual and group briefings with interested stakeholders.

Next steps

We will make our final decisions after carefully considering all submissions received. We will share our decisions and supporting rationale in the form of a decision paper, which we anticipate will be published in the second half of 2025.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this consultation paper is to consult with interested parties on proposed Code amendments[3] to help address the following key common quality issue identified as part of the Authority's review of the common quality requirements in Part 8 of the Code.

> **Issue 1:** An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the 'normal band' of 49.8–50.2Hz, which is likely to be exacerbated over time by decreasing system inertia.

1.2. Proposed amendments to the Code are displayed as follows:

(a) text or formatting is red underlined if it is to be added to the Code

(b) text or formatting is shown in red ~~strikethrough~~ if it is to be deleted from the Code.

1.3. Each Code amendment proposal and its associated regulatory statement is set out in a separate section of this paper. Consistent with section 39(2) of the Act, each regulatory statement contains:

(a) a statement of the objectives of the proposed Code amendment,

(b) an evaluation of the costs and benefits of the proposed amendment, and

(c) an evaluation of alternative means of achieving the objective(s) of the proposed amendment.

1.4. The regulatory statement for each Code amendment proposal also includes an assessment of the proposal against the requirements in section 32(1) of the Electricity Industry Act 2010 (Act). Section 32(1) says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

1.5. We have assessed each Code amendment proposal against the Authority's main objective under section 15(1) of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. We have not assessed the Code amendment proposals against our additional objective under section 15(2) of the Act, which is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The Authority considers our additional objective does not apply to the Code amendment proposals in this paper.

1.6. The regulatory statements are set out in parts 6 and 8 of this paper.

[3] Section 39(1)(c) of the Act requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement.

How to make a submission

1.7. The Authority's preference is to receive submissions in electronic form (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to fsr@ea.govt.nz with "Consultation Paper – Promoting reliable electricity supply: Frequency-related Code amendment proposals" in the subject line.

1.8. If you cannot send your submission electronically, please contact the Authority (at fsr@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.11. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12. Please deliver your submission by 5pm on Tuesday 17 June 2025

1.13. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority at fsr@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Introduction

The Authority is reviewing the Part 8 common quality requirements

2.1. This paper is part of the Authority's multi-year FSR work programme. The FSR programme seeks to ensure New Zealand's power system (at both the transmission and distribution levels) remains secure and resilient as the economy electrifies. The highest priority activity in the FSR work programme is a review of the common quality requirements in Part 8 of the Code.

2.2. Through a combination of one-on-one engagements[4] and formal consultation with interested parties, the Authority has identified seven key issues with the common quality requirements in Part 8 of the Code. The identified issues are:

(a) **Issue 1:** An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the 'normal band' of 49.8–50.2Hz, which is likely to be exacerbated over time by decreasing system inertia.

(b) **Issue 2:** An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause larger voltage deviations, which are exacerbated by changing patterns of reactive power flows.

(c) **Issue 3:** Increasing amounts of inverter-based variable and intermittent resources will reduce the transmission network's system strength thereby increasing the likelihood of network performance issues if inverter-based resources disconnect from the power system.

(d) **Issue 4:** Over time increasingly less generation capacity is expected to be subject to fault ride through obligations in the Code, as more generating stations export less than 30MW to a network.

(e) **Issue 5:** There is some ambiguity around the applicability of harmonics standards and who manages harmonics (including the allocation of harmonics).

(f) **Issue 6:** Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner.

(g) **Issue 7:** The Code is missing some terms that would help enable technologies and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies.

[4] Including with the system operator, distributors, generators, retailers, industry representative bodies, and Transpower as a transmission network owner.

2.3. Addressing these seven common quality issues in a timely manner is consistent with our statutory objectives. The Authority wants the Code's common quality requirements to enable evolving technologies, particularly inverter-based resources. Examples of inverter-based resources include solar photovoltaic generation, wind generation, and battery energy storage systems (BESSs).

2.4. We see these technologies as a key enabler of:

(a) consumers having more choice and flexibility around their electricity use and supply

(b) the electrification of parts of New Zealand's economy, such as transportation and heating.

2.5. In addition to providing opportunities, these technologies do, however, pose some challenges. In particular, we expect that co-ordinating the real-time operation of New Zealand's power system to supply electricity to consumers at the level of reliability they want will become more difficult over the coming years. This increased difficulty will be the result of evolving technologies enabling a significant increase in variable and intermittent generation and an increase in bi-directional electricity flows. There are a number of workstreams within the Authority considering these challenges including the FSR programme's review of Future System Operation.[5]

2.6. We want to address the seven key identified common quality issues in a manner that promotes reliability of electricity supply for consumers. We also want to address these issues in a way that promotes competition in, and the efficient operation of, the electricity industry. We see this as critical to promoting innovation in affordable electricity-related services.

2.7. The Authority's website provides more information on the FSR programme and the context for this Code amendment proposal consultation paper.[6]

5 The future operation of New Zealand's power system

6 See Electricity Authority I Future security and resilience.

3. The problem we want to address

Common quality frequency-related issue (Issue 1)

3.1. The problem we are seeking to address with the two Code amendment proposals in this consultation paper may be summarised as:

> *An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in frequency within the 'normal band' of 49.8–50.2Hz, which is likely to be exacerbated over time by decreasing system inertia*[7].

3.2. The proportion of variable and intermittent generation operating on New Zealand's power system is expected to increase over the next 5–10 years as more wind generation, solar photovoltaic generation, and energy storage systems connect. This is likely to cause more variability in frequency within the range of 49.8–50.2Hz, which is the range the system operator must maintain frequency within other than for momentary fluctuations (defined in the Code as the 'normal band'[8]).

3.3. More frequency variability within the normal band would make it more challenging for the system operator to continuously balance the demand for, and supply of, electricity conveyed across the transmission network.

3.4. For consumers, more frequency variability within the normal band might cause their electrical equipment to operate sub-optimally. In this way, more frequency variability within the normal band would be expected to impose economic costs on consumers. Consumers might also be adversely affected economically by the additional costs associated with the system operator managing system frequency (eg, procuring additional instantaneous reserve to cover for less automatic response from generating units to changes in frequency).

More frequency variability from an increasing amount of variable and intermittent resources, exacerbated by decreasing system inertia

3.5. Compared with international jurisdictions, New Zealand operates a small power system with a small generation base and relatively low inertia. This means:

(a) a small imbalance between electricity demand and supply can cause frequency to deviate outside the normal band of 49.8–50.2Hz

(b) changes in system frequency are much faster than in larger power systems with higher system inertia.

[7] Inertia is the resistance of the power system to changes in frequency, which results from the masses of large spinning generators and motors taking time to slow down or speed up.

[8] The Code requires the system operator to maintain frequency within 0.4% of 50Hz (ie, 49.8–50.2Hz), except for momentary fluctuations. In the case of momentary fluctuations, the system operator must not let frequency drop below 45Hz in the South Island and 47Hz in the North Island, and must return frequency to at least 49.25Hz within 60 seconds. The Code does not specify equivalent upper bounds on frequency fluctuations.

3.6. Wind generation is highly intermittent, which can lead to generation output varying quickly due to wind gusts and potentially shutting down due to low or high wind speed.

3.7. The intermittency of solar photovoltaic generation is also affected by weather – mostly from cloud movement.[9] In addition, solar photovoltaic generation is affected by its daytime-only nature.

3.8. Intermittency of electricity generation output caused by clouds and wind creates difficulty for the system operator in predicting the amount of generation needed from one hour to the next in order to balance electricity demand and supply across the power system. The short-term (second-to-second) balancing of generation with electricity demand is also affected by fast changes in wind speed or cloud movement.[10] This presents a real challenge for the system operator to maintain frequency within the normal band.

3.9. Material increases in behind-the-meter generation also makes system frequency more variable and uncertain:

(a) as net load (ie, as measured on the network side of an installation control point) becomes more variable and elastic/flexible, and

(b) as this generation and distribution network-connected wind generation and solar photovoltaic generation displace the dispatch of synchronous machine-based generation that contributes to frequency regulation capability and system inertia.

3.10. Exacerbating this problem of more frequency variability within the normal band are:

(a) the behaviour of some existing generation in assisting the system operator to manage frequency

(b) the expected relative increase in variable and intermittent generation that either is not required to comply with the frequency-related obligations in Part 8 of the Code or which receives a dispensation from needing to comply with these obligations

(c) the expected fall in system inertia as large thermal generating stations are retired over the coming years, replaced by inverter-based generation.

3.11. The next three subsections expand on these points.

Some existing generation behaviour does not assist in managing frequency

3.12. The behaviour of some existing generation does not assist the system operator in managing frequency. The system operator is observing the following behaviours amongst generating stations:

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9 See Transpower New Zealand Limited, 2017, Effect of Solar PV on Frequency Management in New Zealand.

10 In some instances, cloud movement can cause a fast fluctuation in active power output from solar photovoltaic generation.

(a) Wind, geothermal, solar photovoltaic, and run-of-river hydro generating stations will typically generate as much output as allowed by the fuel source. Therefore, this generation usually has no ability to increase its megawatt output to support the system operator in managing under-frequency, but can reduce output to support the system operator in managing over-frequency.

(b) More and more generators are applying frequency dead bands[11] to their generating units. The system operator advises this is degrading the system operator's ability to manage frequency within the normal band and also adversely affecting the system operator's management of momentary fluctuations.

3.13. Moving forward this will exacerbate the problem of more frequency variability within the normal band caused by increasing amounts of variable and intermittent generation on the power system.

More generation will not have to comply with frequency-related obligations

3.14. Absent a change to the Code, over time the percentage of electricity generating capacity required by the Code to assist in maintaining frequency within the normal band is expected to fall – at least for the foreseeable future. This is based on the following expectations:

(a) There will be a proportional increase in the number of generating stations exporting less than 30MW to a network. This expectation is based on the falling cost of solar photovoltaic generation technology and BESS technology. These technologies lend themselves to smaller-scale installations deployed in a distributed manner across New Zealand's distribution networks for economic and resource availability reasons.

(b) For the foreseeable future, the system operator will continue to grant dispensations to generating stations that have, or will have, assets or a configuration of assets that do not comply with a frequency-related asset owner performance obligation or technical code in Part 8 of the Code. This expectation is based on the system operator continuing to expect that granting such dispensations will not affect the system operator's ability to continue operating the existing power system and meeting its principal performance obligations.[12]

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[11] A frequency 'dead band' in a generating unit's frequency control system halts the generating unit's frequency response within that band. This reduces the generating unit's response to frequency deviations. A dead band can be inherent in moving parts – a generating unit with an inherent dead band will not respond, at least immediately, to small changes in system frequency. A dead band can also be a settable parameter – a frequency control system with a dead band setting of ±0.1Hz will not respond until system frequency is lower than 49.9Hz or higher than 50.1Hz.

[12] See clauses 8.29 and 8.31 of the Code. Clause 8.31 says the system operator must grant such dispensations if the system operator—

(a) reasonably expects it can continue operating the existing power system and meet its principal performance obligations, and

(b) can readily quantify the costs on other persons of the dispensation.

3.15. In accordance with clause 8.38 of the Code, the Authority could, upon receiving an application from the system operator, direct generating stations exporting less than 30MW to a network to support system frequency in the same way as larger exporting generating stations. We could do this if we were satisfied there would be a benefit to the public. However, doing this on a station-by-station basis would be expected to have relatively higher transaction costs than reducing the 30MW threshold if we considered such a reduction would have a benefit to the public.

3.16. The system operator can decline to grant generating stations a dispensation from the frequency-related obligations in Part 8 if the system operator:

(a) reasonably expected it could not continue operating the existing power system and meeting its principal performance obligations, or

(b) could not readily quantify the costs on other persons of the dispensation.[13]

3.17. However, the system operator is expected to continue granting dispensations from the frequency-related obligations in Part 8 to non-synchronous generating stations for the foreseeable future. This is because of:

(a) the characteristics of these non-synchronous generating stations (eg, being unable to maintain pre-event output during a contingent event), and

(b) the likelihood that granting a dispensation to an individual non-synchronous generating station is unlikely to prevent the system operator from operating the existing power system and meeting its principal performance obligations.

3.18. At some point the system operator would be expected to stop granting these dispensations, because the cumulative effect of doing so would be likely to prevent the system operator operating the existing power system and meeting its principal performance obligations. Therefore, there is an inherent upper bound on the amount of electricity generation that will not have to comply with frequency-related obligations.

A fall in system inertia will exacerbate the problem of more frequency variability

3.19. Variable and intermittent inverter-based resources that provide little or no system inertia are, in many cases, replacing thermal generation in New Zealand.[14] This reduction in system inertia means system frequency will change more rapidly in response to supply/demand imbalances. This in turn requires, for a given level of demand, an increased supply of resources for frequency keeping (including more

[13] An asset owner must pay readily identifiable and quantifiable costs borne by others as a result of a dispensation granted to that asset owner. In practice, it is difficult to identify such costs reliably and accurately. Therefore, typically the system operator does not include a cost allocation in a dispensation. A notable exception is a dispensation from certain generator obligations relating to under-frequency, where the Code sets out the cost allocation formula for non-compliant generators.

[14] The Authority notes this is distinct from variable and intermittent resources being built to meet increased electricity demand.

frequency control system response), instantaneous reserve, and potentially automatic under-frequency load shedding (AUFLS).[15]

3.20. Moving forward, a fall in system inertia will exacerbate the problem of more frequency variability within the normal band caused by increasing amounts of variable and intermittent generation on the power system. A fall in system inertia will also exacerbate the rate of change of frequency and the frequency excursion size for an extended contingent event, such as a tripping of the largest connected generating station or both poles of the high voltage direct current (HVDC) link between the North Island and South Island.

3.21. Currently, there is no specific procurement of, or payment for, inertia. Nor are generating stations that do not provide inertia allocated some proportion of the cost of procuring instantaneous reserve and frequency keeping.[16]

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[15] AUFLS is the automatic shedding of electrical load when frequency falls below a pre-set level or falls at a pre-set rate.

[16] An inverter-based resource that uses a 'grid-forming' inverter can provide 'synthetic' inertia. This inverter forms a voltage angle independently of the network to which it is connected and controls its output voltage so as to synchronise with, and remain synchronised with, the network. To date, most inverters installed in New Zealand have been 'grid-following' inverters. This type of inverter tracks the voltage angle of the network to which it is connected, to control the output of the inverter-based resource and thereby remain synchronised with the network. The Authority will review grid-forming inverter technology as part of an investigation into the system strength-related operational challenges that New Zealand's power system is likely to face due to a high level of penetration of inverter-based resources.

4. We have considered a number of options to address the problem

4.1. The Authority considered a range of options to help address the frequency-related issue. We have benefitted greatly from input we have received from the Common Quality Technical Group and the system operator.

4.2. After much consideration, we settled on a short list of three options we considered should be investigated further to help address the frequency-related issue. The options were a subset of a longer list of options that we assessed against a set of evaluation criteria. The evaluation criteria draw from the key principles guiding the consideration of options to help address issues identified in our review of common quality requirements in Part 8 of the Code.

4.3. The three short listed options were consulted on in the *Addressing more frequency variability in New Zealand's power system* consultation paper, that we published on 25 June 2024. This section contains a summary of the key points raised by submitters in response to that consultation paper. Our responses to those points are covered in sections 5 to 8 of this paper, as well as more detailed analysis on each option.

4.4. The evaluation criteria and the process followed to short list options are outlined in the *overview and context for the suite of three consultation papers*[17] published by the Authority on 25 June 2024.

4.5. A list of all options identified to address the frequency-related issue, along with the Authority's initial assessment of each option against the evaluation criteria, is provided in Appendix A of the *Addressing more frequency variability in New Zealand's power system* consultation paper.

We have consulted on three shortlisted options to address the frequency-related issue

4.6. After considering a range of options to help address the frequency-related issue, the Authority settled on a short list of three options to be investigated further:

(a) Option 1: Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations and technical codes in Part 8 of the Code (eg, to 10MW or 5MW).

(b) Option 2: Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

(c) Option 3: Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events.

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4.7. Option 3 was included in the short list of options to help address the frequency-related issue despite this option requiring no changes to the Code. This is because a Code-mandated maximum dead band beyond which a generating station must contribute to supporting frequency has implications for the system operator's procurement of frequency keeping, via ‘multiple provider frequency keeping’ (MFK), and instantaneous reserve. The system operator expects the MFK frequency keeping band may need to widen over the coming years because of variable and intermittent generation causing more frequency variability within the normal band. This widening of the MFK frequency keeping band may not be as large if there is a permitted maximum dead band on all generation in the vicinity of ±0.1Hz.

4.8. As we noted earlier in this paper, we consulted on these three options.

Summary of submissions on the three options outlined in the June 2024 consultation paper

4.9. The Authority received 17 submissions on the June 2024 paper. Submitters were generally supportive of the proposed options. Table 1 lists the submitters.

Table 1: Submitters on June 2024 frequency options paper

Generator/retailer	Generator only	Lines company	Other
Contact Energy	King Country Energy	Aurora Energy	Electricity Engineers' Association
Genesis Energy	Lodestone Energy	Northpower	Independent Electricity Generators Association
Mercury Energy	Manawa Energy	Powerco	Transpower
Meridian Energy	NewPower		Utilities Disputes
	Pioneer Energy		
	SolarZero		

Summary of submissions on Option 1

Challenges and limitations of specific technologies

4.10. Several submitters raised concerns about technology-specific challenges. With the way that intermittent generation (eg, wind and solar) is currently operated, it may not be able to provide under-frequency support when there is no fuel.

4.11. Smaller geothermal units face challenges when operating partially loaded to provide under-frequency support. However, they can contribute to over-frequency management and system inertia.

4.12. Some submitters pointed out that many existing technologies (particularly smaller and older generating stations) may require expensive retrofitting to upgrade to meet under-frequency requirements.

Costs and financial impact

4.13. A lowering of the threshold from 30MW to 5MW or 10MW would disproportionately affect smaller generators, particularly with higher compliance costs. One submitter estimated costs of $5-10m for upgrades, $70-100k for technical reports, and $10-100k for consent variations.

4.14. For existing generating stations, this could make continued operation financially unviable, particularly if they are subject to significant retrofitting and/or compliance costs. This may also deter future investment in smaller generation projects.

4.15. Dispensation costs would increase as a result of more generating stations requiring dispensations due to their inability to comply with the Code requirements. Some submitters suggested a streamlined or less stringent compliance regime for smaller generators to reduce financial burdens.

4.16. For intermittent generators, operating partially loaded or co-locating with a BESS would be necessary, which is costly.

4.17. However, some feedback considered that the proposal would clearly signal the requirements for future generation projects, which would reduce the need for future retrofitting. Also, the proposal would promote competition among generators.

4.18. One submitter made the point that Option 1 would reduce the reliance on AUFLS, and that maintaining the current 30MW threshold is likely to result in increased reserve costs.

Support for market solutions

4.19. Several submitters supported the idea of creating a market for frequency services. They believe a market-driven approach would provide more efficient outcomes and reduce the burden on smaller generators.

Compliance and monitoring challenges

4.20. Concerns were raised about the monitoring and compliance costs faced by smaller generators under a lowering of the 30MW threshold. Smaller generators could be disproportionately affected by the costs associated with control system upgrades, periodic testing, and administrative compliance.

4.21. Some submitters proposed a paper-based compliance approach, or the possibility of assessing compliance for groups of assets rather than on a station-by-station basis, to reduce costs for both asset owners and the system operator.

Threshold preferences and alignment with other requirements

4.22. Some submitters raised a preference for a 10MW threshold instead of 5MW. One reason was to align relatively closely with the wholesale electricity market generator offer requirements in the Code (clause 13.25 of the Code excludes generators from the requirement to submit an offer for generating stations that are 10MW or lower). Submitters also noted the performance gains from lowering the threshold to 5MW instead of 10MW would be marginal, while the costs would be significant.

Mixed views on aligning AS/NZS 4777.2 with the Code requirement for generating stations to ride through an under-frequency event for six seconds

4.23. Submitters expressed mixed views on aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an under-frequency event for six seconds. Most comments fell into one of two categories:

(a) some submitters were in favour of aligning the Code requirements with accepted international standards in general

(b) some submitters considered that more analysis and discussion is needed before forming a view.

4.24. One submitter noted that the Authority might wish to consider how emerging technologies, such as electric vehicles, could be leveraged to provide frequency response. On this point, the Authority notes that, if we decide to investigate this further, we would do so outside of the FSR programme.

Summary of submissions on Option 2

Uniform vs technology-specific dead bands

4.25. Several submitters preferred a uniform dead band for all technologies, as they considered it would simplify power system management. However, other submitters considered that exclusions should be made for some technologies (eg, geothermal) to protect their design lifetimes.

4.26. One submitter argued that a uniform dead band is not a technology-neutral approach. This is because some technology types are inherently better suited for complying with smaller dead bands than others, and as a result the costs of implementing the dead band are likely to vary significantly among different generation technologies.

4.27. Some submitters considered that different technologies contribute differently to the power system. For instance, synchronous generators provide stability (eg, inertia, voltage support) and should not face tighter dead band requirements that are better suited for inverter-based resources. There was also a suggestion that wind turbines are particularly prone to excessive wear and tear from small dead bands.

4.28. Another submitter noted that even within technologies, different dead bands can be appropriate due to specific components or model types (eg, Kaplan vs Francis hydro turbines).

Widening the normal frequency band

4.29. A few submitters supported widening the normal band, considering it a legacy setting that no longer reflects current market conditions. Modern technologies and loads are capable of operating within a wider frequency band.

4.30. However, many submitters disagreed with widening the normal band. This was due to:

(a) concern that this would require more reserves because of the greater risk of triggering an AUFLS event

(b) the perceived benefits being minimal or unknown

(c) the view that increases in frequency keeping will not eventuate as quickly as expected

(d) the possibility of worsening synchronisation challenges for generators that do not have governors

(e) New Zealand already having a wide normal band compared to other jurisdictions

(f) dead band policies perhaps being a more effective alternative.

Implementation costs and challenges

4.31. Feedback from submitters noted the cost of implementing dead bands varies significantly depending on the type of generation. Geothermal and wind generation could face high costs due to wear and tear, energy spillage and equipment upgrades.

4.32. Some submitters emphasised that costs can also vary significantly on a station-by-station basis even within the same technology type, and that providing an accurate estimate of costs is difficult without assessing each station individually. There would likely need to be significant expenditure on consultants to conduct the necessary work.

4.33. Submitter feedback pointed to a likely increase in dispensation applications from asset owners in relation to generating plant that was unable to comply with a new dead band requirement, as well as compliance monitoring, validation testing and certification to demonstrate capability.

4.34. Some submitters suggested a phased implementation or simplified testing requirements. They noted there are limited resources for testing and implementing changes in the New Zealand electricity industry, so a managed approach may be necessary for the industry to effectively transition to new requirements.

4.35. Another piece of submitter feedback was that a uniform dead band would simplify system management, reducing costs.

Long-term vs interim solutions

4.36. Multiple submitters favoured moving directly to a market-based solution for maintaining frequency, suggesting this would be more efficient and cost-effective than interim solutions. There was concern that an interim solution could result in increased power system costs without delivering significant benefits.

4.37. Additionally, there was a suggestion to restructure the instantaneous reserve market to better incentivise inverter-based resources to contribute to frequency control.

Impact on equipment

4.38. Concerns were raised that tighter dead bands could lead to increased wear and tear on certain technologies like wind turbines, which could reduce their lifespan. BESSs used for frequency regulation could also end up with a reduced state of charge and shortened lifespan, impacting their ability to support the supply of electricity to meet peak demand.

4.39. Implementing dead bands on geothermal units was seen as impractical based on the consideration that they are better utilised when fully loaded.

Frequency response and ramp rates

4.40. There was some support for minimum ramp rates, which would ensure generators using the same technology could provide frequency response that was consistent with each other.

Summary of submissions on Option 3

Main benefits of Option 3 identified by submitters

4.41. Some submitters believed that using existing frequency-related ancillary services may be more efficient as it would not alter or introduce new Code obligations on industry participants.

4.42. Another point of view was that modern technology may increase the supply of frequency keeping and instantaneous reserve, which could lead to lower procurement costs.

4.43. Feedback noted that the flexibility of Option 3 allows participants to assess the risk and benefit of offering into the ancillary services market, and to adjust their operations based on plant-specific capabilities.

Main costs of Option 3 identified by submitters

4.44. Some submitters noted the opportunity cost of not developing a capacity market for frequency services, which could better incentivise BESS projects and further stabilise system frequency. There was also support for creating a very fast (1 second) reserve category, which would help mitigate the reduced inertia in the system.

4.45. Some feedback raised concerns that Option 3 would not solve the underlying issue of frequency fluctuations – it is a management tool. This could lead to higher procurement costs as more intermittent generation comes online.

4.46. Some submitters considered that the status quo, including the current MFK band, may not always be appropriate for all time periods, such as during peak demand.

We have decided to progress two options at this point in time

4.47. After carefully considering submitter feedback on the June 2024 consultation paper and undertaking further investigation and analysis, the Authority proposes to amend the Code to implement Options 1 and 2.

4.48. No changes to the Code are required to implement Option 3. Rather the system operator will monitor the suitability of the MFK quantities it purchases under ancillary service contracts and adjust these as necessary to enable the system operator to comply with its principal performance obligations under the Code.

4.49. The system operator considers that introducing a ±0.1Hz maximum permitted dead band under Option 2 could help maintain the effectiveness of the existing MFK band of ±15MW. However, the system operator notes the extent of this effectiveness will depend on broader power system conditions and future changes in generation.

We intend to consider other options in the future

4.50. The Authority is deliberately focusing on options with a shorter Code development timeframe. However, we are not forgetting about options that would require a longer period to develop and implement in the Code. We will turn our focus to these as soon as time and resources permit.

5. Code amendment proposal 1: Smaller generating stations to comply with frequency-related obligations

Option 1 as described in the June 2024 consultation paper

5.1. The Authority published the consultation paper *Addressing more frequency variability in New Zealand's power system* on 25 June 2024. The paper described Option 1 as follows.

5.2. Under Option 1, clause 8.21 of the Code would be amended to lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations and technical codes in Part 8 of the Code.

5.3. Part 8 of the Code contains asset owner performance obligations that specify the contributions generators must make to maintaining frequency in the normal band. Clause 8.17 of the Code sets out the overarching requirement on generators to:

> "*make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to within the normal band)".*

5.4. Clause 8.17 also requires such contributions to be assessed against the technical codes in Schedule 8.3 of Part 8, which include the requirement on generators to:

(a) ensure that each of their generating units has a speed governor and/or frequency control system (the purpose of which is to automatically adjust the generating unit's output in response to changes in system frequency)

(b) agree appropriate speed governor and/or frequency control system settings with the system operator.[18]

5.5. Clause 8.19 of the Code contains requirements for generators, North Island distributors and direct consumers, South Island transmission network owners, and the HVDC link owner to contribute to supporting frequency during under-frequency events.

[18] See clause 5(1) of Technical Code A of Schedule 8.3.

The Authority has considered submitter feedback and undertaken further analysis

5.6. The Authority has considered submitter feedback on Option 1, as described in our June 2024 consultation paper, and undertaken further investigation and analysis of the option.

5.7. This section sets out our investigation and analysis, and a Code amendment proposal based on Option 1.

The Authority proposes to require generating stations exporting 10MW or more to comply with frequency obligations

5.8. To improve the stability of power system frequency, the Authority proposes to amend the Code to require generating stations exporting 10MW or more to comply with the frequency-related asset owner performance obligations.

5.9. We note the system operator's 2024 report on a lower threshold recommended a 5MW threshold.[19]

5.10. The Authority considers that a 10MW threshold is more appropriate than a 5MW threshold, because:

(a) The study report demonstrated the benefits of a 5MW threshold to be relatively minor for the power system, compared to a 10MW threshold.

(b) A 10MW threshold is more consistent with the threshold in Part 13 of the Code, which states that generators are not required to submit offers for generating stations that are 10MW or smaller.

(c) A 10MW threshold should impose minimal, if any, additional costs associated with installing a data transmission communication system. Clause 6(1) of Technical Code C of Schedule 8.3 of the Code requires asset owners to have a primary means of transmitting data between the assets of the asset owner and:

(i) a supervisory control and data acquisition (SCADA) remote terminal unit of a transmission network owner, or

(ii) the system operator.

Excluded generating stations do not have to comply with this requirement. However, generating stations above 10MW should already have this system in place due to the requirements in Part 13. If the 30MW threshold were to be lowered to 5MW, some generating stations that previously were not required to comply with this requirement would be faced with the cost of setting up this new system.

[19] See Appendix C of our June 2024 consultation paper.

Lowering the 30MW threshold would help support frequency during under-frequency events

5.11. Excluded generating stations are not required to comply with the under-frequency ride through obligations in clause 8.19 of the Code.

5.12. Lowering the 30MW threshold would require more generating stations to comply with clause 8.19 (ie, those exporting 10MW or more of electricity but less than 30MW). The benefit of requiring smaller generating stations to comply with this clause's requirements would be the additional support of power system frequency provided during under-frequency events (from more generators remaining synchronised and maintaining their pre-event output).

5.13. The Authority acknowledges submitter feedback that some generation types, such as wind, solar photovoltaic, and geothermal are typically operated at or near their full available capacity. As a result, they may not be able to increase their output or, in the case of wind and solar photovoltaic generation, sustain pre-event output should their intermittent energy source (ie, wind or solar irradiance) decrease.

5.14. However, we note there is currently no requirement for these generators to operate below their maximum available capacity in order to be able to increase output during an under-frequency event. Intermittent generators are considered to meet the clause 8.19 requirement to maintain pre-event output by continuing to generate at their available capacity, provided their output is in line with their forecast output.

5.15. In addition to offering extra support of system frequency during under-frequency events, the proposal would also reduce the amount of instantaneous reserve the system operator would need to procure to cover the risk of secondary tripping. This is discussed further below.

Lowering the 30MW threshold would improve visibility of generation that may be at risk of secondary tripping

5.16. With the number and proportion of generating stations under the 30MW threshold expected to increase over the coming years, the risk of secondary tripping of generating stations is also expected to increase. This will result from these relatively smaller generating stations disconnecting from the network in order to prevent possible damage to their equipment from it operating at lower frequencies. Additional secondary tripping of generating stations in turn would cause the system frequency to reduce further, which would:

(a) increase the risk of activating AUFLS, and

(b) require additional instantaneous reserve, to both cover the risk of the largest generating station tripping and to allow for an increased risk of secondary tripping.

5.17. A benefit of reducing the 30MW threshold is that it would improve the system operator's visibility of generating stations at risk of secondary tripping, which would help the system operator to more effectively manage the risk. This would reduce the possibility of tripping an AUFLS block.

The proposal would reduce the future cost of instantaneous reserve

Additional net free reserves would be available

5.18. Net free reserves refer to inherent capabilities of the power system that contribute to frequency stability without requiring explicit procurement. This includes frequency response provided by governors / frequency control systems, and system inertia. Typically, net free reserves provide a very quick response to changes in power system frequency.

5.19. Net free reserves act as an essential buffer for frequency management and frequency support. A higher amount of net free reserves provides the following benefits:

(a) Enhances system response, because it supports the power system to better resist and recover from frequency deviations. It does this by reducing the magnitude and rate of change of frequency during drops in system frequency.

(b) Lowers the risk of frequency collapse, due to the higher inherent stabilising capabilities of the power system.

(c) Reduces the amount of instantaneous reserve needed, the cost of which is not allocated to all potential causers of under-frequency events, which does not necessarily incentivise good frequency response from generators.

An increase in net free reserves reduces the amount of instantaneous reserve needed

5.20. To calculate the amount of instantaneous reserve required for each trading period, the system operator identifies the largest credible contingency event, such as the sudden loss of a large generating unit or station. The magnitude of this risk is the potential generation or load imbalance caused by the event, measured in megawatts.

5.21. The system operator then assesses the amount of net free reserves that can naturally help to stabilise the system frequency. This amount is also measured in megawatts.

5.22. The required amount of instantaneous reserve is determined by subtracting the net free reserves from the identified risk, in megawatts[20]. Therefore, an increase in net free reserves causes a decrease in the amount of instantaneous reserve that must be purchased.

There is a cost associated with net free reserves

5.23. While increasing net free reserves provides system-wide benefits, it may also impose additional costs on generators required to provide frequency response. These costs could arise from increased wear and tear on equipment due to more

[20] In reality the amount of instantaneous reserve does not equal the size of the risk. There can be slight variances due to, for example, secondary risks, contingent event net free reserves and extended contingent event net free reserves, and the role of instantaneous reserve in restoring the system frequency to the normal band rather than to 50Hz.

frequent adjustments in output, higher operational stress and potential efficiency losses.

5.24. However, the Authority considers these costs are likely to be minor compared to the overall benefits of improved frequency stability and reduced reliance on procured instantaneous reserve.

The introduction of BESSs may not solve the frequency-related issue

Potential of BESSs to improve system frequency

5.25. BESSs have the potential to significantly enhance the stability of power system frequency due to the combination of capabilities they can provide:

(a) BESSs can respond to frequency deviations within milliseconds.

(b) Their near-instant bi-directional operation allows them to absorb excess energy when frequency rises and inject energy when it falls, balancing electricity demand and supply quickly.

(c) BESSs are scalable and can be deployed at transmission-level installations or across distribution networks.

(d) By providing fast frequency response, BESSs can mitigate challenges associated with the increasing penetration of variable and intermittent generation and inverter-based resources, and support further growth in electricity demand and generation.

Why BESSs might not improve frequency stability as expected

5.26. Despite their potential, several barriers could prevent BESSs from fully delivering frequency stability benefits:

(a) There are different operating models for BESSs, and the goals and incentives of a BESS owner may not always align with those of the system operator. BESS owners are expected to prioritise services that maximise their revenue streams, which may be at the expense of services that help the system operator to comply with its principal performance obligations under the Code.

(b) BESS is an emerging technology, and market arrangements that can maximise the frequency stability benefits of BESSs are still being developed.

(c) Operational constraints may reduce the effectiveness of a BESS in some situations. For example, its relatively limited energy storage capacity or its provision of other services may reduce its availability to provide frequency support services.

The Authority is considering how the regulation of BESSs promotes consumer benefit

5.27. The introduction of utility-scale BESSs onto New Zealand’s power system is a transformative opportunity to support the common quality of the system. However, there is a lack of historical data to assess how they will be operated.

5.28. The Authority is focused on ensuring BESSs are operated in a manner that promotes the long-term benefit of consumers. We will regulate as necessary to ensure BESSs are operated in a manner promoting competition in, reliable supply by, and the efficient operation of the electricity industry, for the long-term benefit of consumers.

5.29. The Authority is considering common quality requirements and electricity market structures for BESSs, and energy storage systems more generally, that promote the long-term benefit of consumers.

5.30. From a common quality standpoint, we recently amended the Code to treat any energy storage system that is not an 'excluded generating station'[21] as generation for the purposes of Part 8 of the Code. This amendment's objective is for the Code to enable the capabilities of energy storage systems, including BESSs, to be better realised in relation to supporting common quality on the power system. The amendment will do this while reducing transaction costs associated with energy storage system owners seeking dispensations, equivalence arrangements, or exemptions from their AUFLS obligations under the Code.

5.31. We are now considering what, if any, frequency-related asset owner performance obligations should apply to energy storage systems when they are idle (ie, neither charging nor discharging).

New markets that support frequency stability may be considered

5.32. The Authority's June 2024 consultation paper *Addressing more frequency variability in New Zealand's power system* discussed the Authority's previous plans to investigate the creation of a capability market for frequency response. As the paper noted, we deferred this work until the outcomes of several other Authority projects could be taken into account.

5.33. Many submitters on our June 2024 consultation paper strongly agreed with the suggestion of a capability market, as they considered it would better incentivise industry participants to contribute to maintaining system frequency. The Authority has noted this feedback.

5.34. As noted earlier in this paper, the Authority is deliberately focusing on options to improve the common quality requirements in Part 8 of the Code that have a shorter Code development timeframe. This excludes from our current work, consideration of a capability market.

5.35. However, as also noted earlier, we are not forgetting about options that require a longer Code development and implementation period. The Authority has commenced initial scoping for a review of the purpose and effectiveness of the frequency keeping ancillary service Code arrangements, as part of another workstream. We may do likewise for other options to address the key frequency-related common quality issue that did not make the options short list. An example of one such option is a new service for very fast (less than one second) instantaneous reserve.

5.36. The speed of technological change will be a key influence on what some of these options may look like. Energy storage systems are an example of the blurring of the traditional delineation between supply-side and demand-side technologies.

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[21] See clause 8.21 of the Code, which says an excluded generating station is a generating station that exports less than 30MW to a local network or to the transmission grid (unless the Authority directs otherwise).

Continued technological evolution might be expected to give rise to opportunities for more consumer involvement in supporting common quality in the future.

5.37. The Authority considers that even if a new product or market were implemented in the future, the frequency-related asset owner performance obligations in Part 8 of the Code would continue to be necessary until any new product or market clearly demonstrated it could replace the existing requirements.

5.38. In addition, establishing physical capability in smaller generating stations now prepares these assets for potential future developments like a capability market.

Capital costs imposed on new generating stations are expected to be minor

5.39. Lowering the 30MW threshold for excluded generating stations is not expected to impose significant capital costs on new generating stations that export 10MW or more. Modern technology used in new generating units, regardless of size, is designed to have the capability to contribute to frequency management and to frequency support. In particular, modern generation technology has the capability to ride through an under-frequency event and remain connected for the timeframes specified in clause 8.19 of the Code. The cost to enable this capability for suitably equipped plant is minor – it is essentially a software setting.

5.40. Despite the relative immateriality of this cost, there is currently no incentive on generating stations under 30MW with this capability to enable it.

The lower threshold would not apply to generating stations commissioned before 1 July 2026 that are not able to comply without modification unless they are upgraded or increase their export of electricity

Some existing generating stations under the 30MW threshold cannot comply

5.41. Several submitters on our June 2024 consultation raised concerns regarding the cost imposed on them should some of their existing generating stations under 30MW have to comply with the frequency-related asset owner performance obligations in Part 8 of the Code. These generating stations do not have the capability to comply – typically because they do not have the necessary equipment. Expensive retrofitting would be required to achieve compliance with clause 8.17 and/or clause 8.19 of the Code. In some cases this might extend to altering the generating station’s foundations.

5.42. As an example, Manawa Energy estimated that the total cost of its equipment upgrades would likely be in the range of $5m-$10m. There would also be practical issues that needed to be considered, such as the need to apply for consent variations before being able to upgrade existing generating stations.

5.43. In addition to the cost of retrofitting equipment, submitters raised concerns about the costs involved with demonstrating a generating station’s compliance with the frequency-related asset owner performance obligations to the system operator. This is necessary to provide assurance that the generating station will operate as intended and not adversely affect the system operator’s ability to comply with its principal performance obligations.

5.44. Some submitters said these compliance costs at times would likely be higher than the cost of the equipment itself. This was due to these costs including:

(a) consultant fees for dynamic studies

(b) control system changes and pre-testing

(c) on-site frequency response testing

(d) a compliance summary report.

5.45. The Authority acknowledges the concerns raised by submitters. We agree that the cost of retrofitting equipment into existing generating stations to enable compliance with the frequency-related asset owner performance obligations is likely to be cost prohibitive for some existing generating stations.

5.46. The Authority notes Part 8 of the Code provides for the owners of these generating stations to obtain a dispensation from the proposed requirements. However, we consider that relying on the dispensations process would have higher transaction costs than an alternative approach of permitting these generating stations to not comply with the proposed requirements (see the discussion in paragraphs 5.58 - 5.59).

5.47. Therefore, we propose generators not be required to comply with the frequency-related asset owner performance obligations in clauses 8.17 and 8.19 and the frequency-related asset owner obligations in Technical Code A of Schedule 8.3, for any existing generating stations that export 10MW or more but less than 30MW and where the equipment at those stations is not able to comply with these provisions without modification.

5.48. This exception will only apply if the relevant generator notifies the system operator that the generating station is not able to comply with these provisions, via the asset capability statement for that generating station. This information is important for the system operator effectively managing any risk associated with the generating station not being able to comply (eg, procuring instantaneous reserve should the generating station be unable to comply with the under-frequency support obligations in clause 8.19 of the Code).

5.49. The Authority wishes to emphasise that this proposed 'legacy clause' approach[22] is intended to avoid imposing uneconomic upgrades on generators with existing generating stations that export 10MW or more but less than 30MW and which are not able to comply with clauses 8.17 and 8.19 of Part 8 and the frequency-related asset owner obligations in Technical Code A of Schedule 8.3. If these non-compliant generating stations are subsequently upgraded, compliance with the frequency-related asset owner performance obligations would be required.

5.50. We consider the following would constitute an upgrade to a generating station that is subject to the 'legacy clause' under the proposed Code amendment:

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[22] A legacy clause is also known as a 'grandfather/ing clause'.

(a) the generating station is changed in such a way as to have the capability to comply with the above frequency-related asset owner performance obligations in the Code, or

(b) the generating station's export capacity is increased.

5.51. A 'like-for-like' replacement of equipment in the generating station with identical equipment (ie, of the same technology) would not constitute an upgrade (eg, a 10MW induction generating unit is replaced with another 10MW induction generating unit).

Proportionate compliance requirements

5.52. The Authority intends to ensure that compliance requirements for future generating stations are proportionate to the size and impact of the generating station.

5.53. We are working with the system operator on options to achieve this, with consultation planned for later in 2025.

The system operator would still be able to meet its principal performance obligations

5.54. Adopting the 'legacy clause' approach set out in the preceding sub-section would not adversely affect the system operator's ability to comply with its principal performance obligations.

5.55. Another consideration is that the number of generating stations subject to the 'legacy clause' would be expected to decline over time as they reach the end of their operational life and are upgraded or replaced.

5.56. The above factors indicate that while it is desirable, it is not totally necessary for existing generating stations exporting 10MW or more but less than 30MW to comply with the frequency-related asset owner performance obligations in the Code.

5.57. However, as discussed in our description of the problem we are addressing, in the future it will be necessary for new generating stations exporting 10MW or more of electricity to comply with the frequency-related asset owner performance obligations. This is to help the system operator manage the system frequency as the proportion of smaller generating stations on the power system increases.

Dispensations are not a costless alternative

5.58. Generators can apply to the system operator for a dispensation if they cannot meet the frequency-related asset owner performance obligations in Part 8 of the Code. However, there is a cost associated with this process. Based on historical data, the Authority estimates the total cost of a dispensation application to be approximately $15,000-$25,000, on average. This includes:

(a) the application fee payable by the asset owner to the system operator

(b) the asset owner's costs of preparing the application, including the completion of required supporting information such as testing results and studies

(c) the system operator's time and resources to assess the application.

5.59. Data held by the Authority and the system operator indicates there are 17 existing generating stations that would likely need to apply for dispensations if the threshold for compliance with the frequency-related asset owner performance obligations were to be lowered to 10MW and there were to be no 'legacy clause' provision. Based on the historical cost data referred to above, the cost on the electricity industry of processing 17 dispensations would be approximately $250,000–$425,000. This cost estimate would be expected to increase if other generating stations were to seek dispensations (eg, generating stations under construction at the time the proposed Code amendment came into effect.

Proposed 'legacy clause' provisions

5.60. The Authority has included in the proposed Code amendment the following 'legacy clause' provisions:

(a) owners of generating stations commissioned before the effective date of the Code amendment and which export 10MW or more but less than 30MW do not need to comply, in respect of those generating stations, with:

(i) the frequency-related asset owner performance obligations in clauses 8.17 and 8.19, and

(ii) the provisions in Technical Code A of Schedule 8.3 relating to the obligations of asset owners in respect of frequency

(b) the above only applies:

(i) in respect of generating stations that are not able to meet these requirements without modification, and

(ii) if the relevant owner of the generating station updates the asset capability statement for that generating station to record that it cannot meet these requirements

(c) the system operator must publish on its website a list of generating stations that do not need to comply

(d) the above 'legacy clause' arrangement no longer applies to a generating station if the generating station:

(i) is altered such that it has the capability to meet the above frequency-related Code obligations, or

(ii) increases its generation export capacity (measured against an amended, generalised, definition of maximum export power).

Proposed Code amendment

5.61. The Authority proposes to amend:

(a) clause 1.1, to generalise the definition of "maximum export power"

(b) clause 8.21, to lower the 30MW threshold for a generating station to comply with the frequency-related asset owner performance obligations in Part 8 of the Code.

5.62. The Authority's proposed Code amendments are as follows:

Part 1
Preliminary provisions

…

1.1 Interpretation

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

…

~~**maximum export power** means the maximum **active power** exported into the **local network** or **embedded network** at an **ICP** of a **distributed generator**, and is equal to—~~

~~(a) the **nameplate capacity** of the **distributed generation** minus the minimum load at the **point of connection**; or~~

~~(b) the power export limit imposed by an active export control device~~

maximum export power means, in respect of a **generating plant**, the lesser of—

(a) the **nameplate capacity** of the **generating plant** minus the minimum load at its **point of connection**; or

(b) the power export limit imposed by an **active power** export control device

…

Part 8
Common quality

…

8.21 Excluded generating stations

(1) For the purposes of—

(a) clauses 8.17, 8.19, ~~8.25D,~~ and the provisions in **Technical Code** A of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** that has a **maximum export power** of less than 10 **MW**~~exports less than 30 **MW** to a **local network** or the **grid**~~, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.17, 8.19, ~~8.25A, and 8.25B~~ and the relevant provisions in **Technical Code** A of Schedule 8.3; and

(b) clause 8.25D, an **excluded generating station** means a **generating station** that has a **maximum export power** of less than 30 **MW**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.25A and 8.25B.

(2) Whether likely to be **an excluded** ~~**generation**~~ **generating** **station** or not, a **generator** who is planning to connect to the **grid** or a **local network** a **generating unit** with rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.) capacity) must provide the **system operator** with written advice of its intention to connect together with other information relating to that **generating unit** in accordance with clause 8.25(4).

(3) A **generating station** that was an **excluded generating station** immediately before 1 July 2026 that would no longer be an **excluded generating station** due to the commencement of the [name of the amending instrument] continues to be an **excluded generating station** if—

(a) it is not able to comply, without modification, with one or more of the requirements it would be subject to if it was no longer an **excluded generating station**; and

(b) the **asset owner** of the **generating station** updates the **asset capability statement** for the **generating station** to record that this subclause applies to the **generating station**.

(4) Subclause (3) ceases to apply in respect of a **generating station** from the date—

(a) a modification is made to the **generating station** that means it is able to meet all the requirements it would be subject to if it was not an **excluded generating station**; or

(b) the **generating station's maximum export power** increases above its **maximum export power** immediately before 1 July 2026.

(5) An **asset owner** must, as soon as practicable, update the **asset capability statement** for a **generating station** to record when subclause (3) ceases to apply to the **generating station**.

(6) The **system operator** must **publish** and maintain a list of **generating stations** to which subclause (3) applies.

6. Code amendment proposal 1 regulatory statement

Objectives of the proposed amendment

6.1. The objective of the proposed Code amendment is to enhance the system operator’s ability to comply with its principal performance obligations in Part 7 of the Code, by requiring generating stations that export 10MW or more of electricity to comply with the frequency-related asset owner performance obligations in Part 8 of the Code.

The proposal is consistent with our main statutory objective

6.2. The Code amendment proposal is consistent with the Authority’s main statutory objective, in particular the reliability limb.

6.3. The proposal promotes reliable supply by the electricity industry by requiring more generating stations to support the stability of frequency on the power system. This is expected to strengthen the resilience of the power system by, in particular, reducing the possibility of AUFLS being activated and reducing the potential for cascade failures on the power system.

6.4. We expect the proposal will also promote the efficient operation of the electricity industry by requiring some generating stations that currently contribute to the risk of under-frequency events to instead remain connected. This will reduce the system operator’s need to procure instantaneous reserve to cover the risk of secondary tripping by these generating stations.

An evaluation of the costs and benefits of the proposed amendment

Summary of main benefits and costs

6.5. The main benefit of the proposal is that it reduces the likelihood of inadvertent AUFLS block tripping, by improving the system operator’s visibility of generating stations that pose secondary tripping risks, helping to avoid the associated costs of AUFLS events.

6.6. A secondary benefit is the avoided cost of additional instantaneous reserve, achieved by enhancing power system stability and resilience to under-frequency events.

6.7. The Authority expects the costs of the proposed amendment to be minor because they primarily apply to new or upgraded generating stations exporting 10MW or more but less than 30MW. As noted earlier in this paper (see paragraph 5.39), modern generation technology is designed to have the capability to contribute to frequency management and to frequency support. Under the proposal, costly retrofits for existing generating stations are avoided, with compliance only required when a station can reasonably meet the requirements.

6.8. Table 2 summarises the main identified benefits and costs of Code amendment proposal 1. The Authority considers that the benefits of the proposal materially outweigh the costs of the proposal.

Table 2: Summary of identified benefits and costs of Code amendment proposal 1

Category	Description
Benefits	Avoided cost of inadvertently tripping first AUFLS block
	Avoided cost of procuring additional instantaneous reserve
	Improved system stability
	Improved visibility for the system operator of generating stations that are at risk of secondary tripping
Costs	Compliance-related costs for generators
	Administrative costs for generators and the system operator
	Additional wear and tear costs for generators

The proposal will reduce the likelihood of an AUFLS event

6.9. Excluded generating stations do not have to comply with the Code's frequency-related asset owner performance obligations, including remaining connected to the network during an under-frequency event. Nor do excluded generating stations have to demonstrate their asset capability to the system operator.

6.10. The system operator does not procure instantaneous reserve to cover the risk of sympathetic tripping if the system operator is unaware of the risk. This gives rise to the potential for an AUFLS block to be activated during a contingent event that causes an under-frequency event.

6.11. Code amendment proposal 1 would require more generating stations to comply with the under-frequency event ride-through requirements in clause 8.19 of the Code. This will ensure generating stations that export 10MW or more have the capability and obligation to remain connected and to support frequency during under-frequency events. This will thereby reduce the likelihood of AUFLS being activated and the potential for cascade failures on the power system. In the event that a generating station was unable to comply with the requirements of clause 8.19, the system operator would have visibility of this and be able to manage the risk through the procurement of additional instantaneous reserve.

6.12. Currently, if the first AUFLS block were to be inadvertently tripped in the North Island during summer, in the middle of the day (when solar photovoltaic generation was at its highest), approximately 300MW (10% of 3,000MW) of North Island load could be lost. The estimated value of expected unserved energy in this scenario would be approximately $6m per hour, using the $20,000 per MW hour value specified in clause 4(1)(a) of Schedule 12.2 of the Code.

6.13. This estimate is intended to provide an indication of the potential scale of costs rather than be a precise forecast. The frequency of an AUFLS event resulting from a lack of visibility of secondary tripping risks is difficult to predict, adding uncertainty to any annualised cost assessment.

The proposal will avoid possible costs of procuring additional instantaneous reserve

6.14. If no action is taken, the system operator may need to procure additional instantaneous reserve to cover the risk of the system operator being unable to manage frequency within the limits mandated by the Code.

6.15. Wind and solar photovoltaic generation is expected to displace quantities of machine-based synchronous generation in the merit order for generation dispatch going forward. This would reduce the amount of under-frequency response provided by the governors and frequency control systems of machine-based synchronous generation. This expected reduction in under-frequency response is premised on wind and solar photovoltaic generation operating at its maximum available output, thereby removing its ability to support frequency during an under-frequency event.

6.16. Currently, the system operator's 'Reserve Management Tool' factors in the available response of governors and frequency control systems to under-frequency events when determining how much instantaneous reserve is needed to cover the binding risk[23] in any given trading period. As the response of governors and frequency control systems to under-frequency events reduces, more instantaneous reserve will be required to cover the same-sized binding risk.

6.17. It is difficult to accurately quantify the avoided cost of procuring additional instantaneous reserve as a result of the proposed Code amendment. However, we expect it to be material. Let us assume the system operator was able to confirm that an excluded generating station that exported 24MW, on average, is at risk of sympathetically tripping during an under-frequency event. The system operator would cover the risk of this sympathetic tripping by procuring additional instantaneous reserve whenever the generating station was the binding risk. Under the following assumptions the system operator would need to procure approximately $262,800 of fast instantaneous reserve[24] per year:

(a) a generating station with an average export of 24MW that is unable to ride through frequency events, is the binding risk for 12 trading periods per day

(b) a cost of $5/MW per trading period, based on the approximate average price of fast instantaneous reserve in the North Island over the five years up to 31 December 2024

(c) a fast instantaneous reserve factor of 0.5, resulting in the need to buy an extra 12MW of fast instantaneous reserve for the affected trading periods.

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[23] Binding risk refers to the largest credible contingency considered by the system operator when determining the required level of instantaneous reserve. It represents the generation or transmission asset whose sudden failure would have the greatest impact on system frequency, requiring reserves to be procured to maintain system stability.

[24] Fast instantaneous reserve means the increase in generation or reduction in demand (in MW) provided no later than 6 seconds after the start of a contingent event, and that is sustained until at least 60 seconds after the start of the contingent event.

6.18. This estimate is intended to illustrate the potential materiality of the avoided cost rather than provide a precise forecast. Actual costs will vary depending on market conditions at the time and the system operator's future procurement strategies.

The proposal may assist in avoiding sub-optimal operation of some electrical equipment

6.19. For consumers, more frequency variability within the normal band might cause their electrical equipment to operate sub-optimally. Therefore, to the extent that Code amendment proposal 1 assists in reducing frequency variability over time, the proposal may lessen the possibility of this economic cost for consumers.

The costs of the proposal are being reduced through the method of implementation

6.20. The Authority has received feedback from submitters on the costs of implementing the proposed amendment, which would mainly apply to generators. However, most of those costs would only apply if existing generating stations had to upgrade their equipment and systems to comply with the frequency requirements.

6.21. We are proposing to adopt a 'legacy clause' approach under the proposed amendment. This will avoid the need for some owners of existing generating stations that export 10MW or more but less than 30MW to seek a dispensation from the frequency-related obligations. We expect such dispensations would be granted to generation owners who would otherwise face uneconomic upgrades in order to comply with the frequency-related obligations.in

6.22. In contrast, the cost imposed on the owners of new generating stations is expected to be significantly lower. This is due to the following factors:

(a) modern equipment and technology used in new generating stations are typically designed to meet these requirements as standard

(b) it is more cost-effective to incorporate compliance measures during the initial design and construction phase of a project, rather than retrofitting them later

(c) many imported components are already designed for use in jurisdictions with more stringent frequency requirements.

6.23. For owners of new generating stations, there are alternative options if a generating station is unable to comply with the frequency requirements. The owner could submit an application to the system operator for:

(a) an equivalence arrangement, if the applicant is seeking to contract out the provision of frequency contributions to another provider

(b) a dispensation, which would require the applicant to pay any identified costs that would be imposed on other participants as a result of the dispensation.

6.24. The proposal would require generating stations exporting 10MW or more to comply with the frequency-related periodic testing provisions in Appendix B of Technical Code A in the Schedule 8.3 of the Code. The cost of complying with the current requirements is estimated at approximately $100,000–$200,000 per generating station for each periodic test. However the Authority is working with the system operator to develop an alternative that significantly reduces these costs.

6.25. As part of this approach, the system operator is looking to put testing requirements and associated guidance for asset owners in a new system operation document that can be incorporated by reference in the Code (subject to an associated Code amendment proposal being developed by the Authority). This new document will explore a simplified testing approach for generating stations that export 10MW or more but less than 30MW, including:

(a) allowing asset owners to use high-speed power quality data to demonstrate compliance with clause 8.17, potentially removing the need for periodic testing

(b) considering a paper-based compliance approach for clause 8.19, enabling assessments to be conducted using existing documentation.

6.26. This new system operation document is being developed as part of the Authority's work to address the information issue identified as part of our review of the common quality requirements in Part 8 of the Code. We expect to release a consultation document in mid-2025.

The proposal may increase wear and tear costs for some asset owners

6.27. There is expected to be an increase in wear and tear costs for generating stations newly required to comply with the frequency-related asset owner performance obligations. However, for generating stations that already comply, the proposal may reduce wear and tear costs as there will be more generating stations sharing the burden. The actual impact on wear and tear costs is expected to be minor.

The proposal may place some costs on some industrial consumers

6.28. For some consumers with on-site generation integral to their industrial processes, the obligation for the generation to remain connected during an under-frequency excursion may result in on-site processes being disrupted by the frequency excursion. This would depend on the sensitivity of the on-site processes to variations in frequency.

6.29. We have been unable to assess the magnitude of this potential cost. We received no feedback from industrial (or other) consumers on the extent or size of this potential cost in response to our June 2024 consultation.

An evaluation of alternative means of achieving the objectives

6.30. As discussed in section 4, the Authority, working in particular with the Common Quality Technical Group and system operator, has identified and evaluated a range of alternative options. These options were described in our June 2024 consultation paper *Addressing more frequency variability in New Zealand's power system*, along with the assessment of each option. That assessment is adopted and incorporated into this regulatory statement and is summarised in the paragraphs below. The Authority does not consider that there have been any changes to the underlying circumstances in the industry since that earlier consultation that materially changes any part of that analysis. The Authority's responses to submissions on the preferred option and the alternative options as set out in the June 2024 consultation paper is set out above.

6.31. A new capability market for frequency support, as supported by several submitters on our June 2024 consultation, may be a credible alternative. However, the long development and implementation timeframe means this alternative would not help address the identified problem for several years. The Authority is focused, at least for now, on solutions that deliver benefits in the shorter term rather than the medium to long term. As discussed earlier in this paper, this alternative may be considered at a later date, as part of another Authority workstream.

6.32. Introducing a new reserve product (eg, very fast (<1 second) instantaneous reserve) may also be an alternative. This also received some support in submissions on our June 2024 consultation. However, this alternative faces similar timeline constraints as a capability market.

6.33. A further alternative might be to increase, from 45Hz to 47Hz, the minimum frequency at which South Island generation assets must remain synchronised for 30 seconds following an under-frequency event. One submitter on our June 2024 consultation supported this option. However, as described in the Authority's June 2024 assessment of options,[25] this would likely be expensive and have a long implementation timeframe. It is also unclear the extent to which this option would address the identified issue of greater variability in frequency.

6.34. Procuring additional instantaneous reserve is a feasible option but does not address the need to manage frequency within the normal band of 49.8–50.2Hz. The procurement of instantaneous reserve is focused on mitigating contingencies on the power system rather than managing frequency stability.

6.35. For the reasons above, and as set out in the June 2024 consultation paper, the Authority prefers the option proposed in this paper.

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

6.36. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to direct dealings between industry participants and these consumers.

6.37. Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

6.38. The Authority considers that Code amendment proposal 1 is necessary or desirable to promote reliability and efficiency in the electricity industry. The proposal enhances the system operator's ability to comply with its principal performance obligations in Part 7 of the Code by requiring more generating stations to comply with the frequency-related asset owner performance obligations in Part 8 of the

[25] See Appendix A of our June 2024 consultation paper.

Code. This will strengthen the management and support of frequency on New Zealand's power system, thereby contributing to a more stable and secure power system.

The proposed amendment complies with section 17(1) of the Act

6.39. Under section 17(1) of the Act, the Authority in performing its functions, must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister of Energy. Table 3 below sets out our consideration of the Government Policy Statement on Electricity.[26]

Table 3: Consideration of the proposed amendments against the Government Policy Statement on Electricity

Clause	Consideration
2. The Government expects the electricity system to deliver reliable electricity at lowest possible cost to consumers. It should serve the interests of all electricity consumers, including through the provision of sufficient electricity infrastructure to ensure security of supply and avoid excessive prices.	The proposal aligns with the Government Policy Statement as it: • strengthens the reliability and resilience of the power system. It achieves this by enhancing the system operator's ability to comply with its principal performance obligations, by requiring more generating stations to support the stability of frequency on the power system. • is expected to lead to overall cost savings by reducing the amount of ancillary services that need to be procured by the system operator, thereby improving economic efficiency.
8. The Government's role is to ensure clear and consistent regulatory settings, reflected in market rules with robust compliance monitoring and enforcement, that enable an efficient market anchored by accurate price signals, and effective risk management tools and competition.	The proposal aligns with the Government Policy Statement as it promotes clear and consistent regulatory settings across a broader range of industry participants, via rules that have robust monitoring and enforcement provisions.
32. The Electricity Authority is expected to work collaboratively with other agencies across the wider regulatory regime, acknowledging the scope of each agency's remit.	The Authority has collaborated with other agencies during the policy development phase and will continue to collaborate as applicable through any implementation.

[26] New Zealand Government. Government Policy Statement on Electricity - October 2024.pdf.

The Authority has given regard to the Code amendment principles

6.40. When considering amendments to the Code, the Authority is required by our Consultation Charter to have regard to the following Code amendment principles, to the extent that the Authority considers they are applicable. Table 4 describes the Authority's regard for the Code amendment principles in the preparation of Code amendment proposal 1.

Table 4: Regard for Code amendment principles

Principle	
1. Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	The problem definition is set out in section 3 of this paper. An increasing amount of variable and intermittent generation is likely to cause more variability in frequency within the normal band, which is likely to be exacerbated over time by decreasing system inertia. More frequency variability is likely to impose economic costs on consumers by: • causing electrical equipment to operate sub-optimally • increasing the costs associated with the system operator managing the power system frequency.
2. Costs and benefits are summarised	The extent to which the Authority has been able to estimate the proposal's net benefits and efficiency gains is set out in the evaluation of costs and benefits earlier in this section. The proposal's main benefits are improved system stability, the reduced risk of inadvertently tripping an AUFLS block, and the avoided cost of procuring additional instantaneous reserve. The costs associated with the proposal are expected to be relatively minor due to the proposed approach to implementing the proposal.

Q1.1 Do you support the Authority's proposal to amend the Code to require smaller generating stations to comply with frequency-related asset owner performance obligations?

Q1.2 Do you consider the 'legacy clause' provisions in the Code amendment proposal should apply to a generating station for a finite period of time (eg. 10 years)? Please explain your answer.

Q1.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.

Q1.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.

Q1.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?

Q1.6 Do you have any comments on the drafting of the proposed amendment?

7. Code amendment proposal 2: A maximum dead band beyond which a generating station must contribute to frequency management and support

7.1. As noted in section 4 (see paragraph 4.47), the Authority proposes to amend the Code to implement a second short-listed option to address the frequency-related issue identified in our review of common quality requirements in Part 8 of the Code.

Option 2 as described in the June 2024 consultation paper

7.2. The Authority published the consultation paper *Addressing more frequency variability in New Zealand's power system* on 25 June 2024. The paper described Option 2 as follows.

7.3. Under Option 2, clause 5 of Technical Code A of Schedule 8.3 of the Code would be amended to set a permitted maximum dead band beyond which a generating unit would have to contribute to frequency keeping and instantaneous reserve. This obligation would apply to existing and new generating units.

7.4. A frequency 'dead band' in a generating unit's frequency control system halts the generating unit's frequency response within that band. This reduces the generating unit's response to frequency deviations. A dead band can be inherent in moving parts – a generating unit with an inherent dead band will not respond, at least immediately, to small changes in system frequency. A dead band can also be a settable parameter – a frequency control system with a dead band setting of ±0.1Hz will not respond until system frequency is lower than 49.9Hz or higher than 50.1Hz.

7.5. Currently, clause 8.17 of the Code is silent on whether a generator can apply a dead band setting to a speed governor or frequency control system to halt the generating unit's frequency response within that band.

7.6. More and more generators are applying frequency dead bands to their generating units to reduce wear and tear on their equipment caused by responding to frequency fluctuations. The system operator advises this is degrading the system operator's ability to manage frequency within the normal band and also adversely affecting the system operator's management of momentary fluctuations.

The Authority has considered submitter feedback and undertaken further analysis

7.7. The Authority has considered submitter feedback on Option 2, as described in our June 2024 consultation paper, and undertaken further investigation and analysis of the option.

The Authority proposes to specify a maximum permitted dead band of ±0.1Hz

7.8. To improve the stability of power system frequency, the Authority proposes to amend the Code to insert a maximum permitted dead band of ±0.1Hz. This decision reflects:

(a) international experience – narrower dead bands significantly benefit frequency management

(b) New Zealand's characteristics – a slightly wider dead band than that seen in some overseas jurisdictions accommodates a greater amount of existing generation while still supporting the stability of the power system frequency.

A maximum permitted dead band would support maintaining frequency within the normal band

7.9. Establishing a maximum permitted dead band for generating units would help maintain frequency within the normal band of 49.8–50.2Hz. It would also help to manage the quality of frequency within the normal band (ie, keep frequency closer to 50Hz).

7.10. Wide or inconsistent dead bands applied across generating units can reduce the overall frequency responsiveness of the power system, making it more difficult for the system operator to manage frequency deviations effectively.

7.11. Requiring all generators to contribute to frequency management within a defined range that is narrower than the normal band helps the power system to respond better to fluctuations in electricity demand and supply, reducing the risk of frequency excursions outside the normal band. This approach would also reduce the current reliance on a relatively small number of generators to help the system operator manage frequency within the normal band.

The future costs of frequency keeping would be relatively lower

7.12. After undertaking power system studies,[27] the system operator has concluded that introducing an appropriate maximum permitted dead band would improve the management of power system frequency. This could help maintain the effectiveness of the current MFK band of ±15MW, though the extent of this effectiveness would depend on broader system conditions and future changes in generation.

7.13. Absent such a dead band, the system operator expects the existing MFK band would need to be widened sooner, resulting in increased frequency keeping ancillary service costs. This would be because of more variable and intermittent generation connecting to the power system and operating at maximum output, and thereby not contributing to lifting frequency when it approaches 49.8Hz.

7.14. The increase in frequency keeping ancillary service costs is expected to be relatively higher than the increase in costs faced by generators with generating units operating with a dead band of ±0.1Hz.

[27] See Appendix D of our June 2024 consultation paper.

Disproportionate wear and tear on some generators would be reduced

7.15. In order to respond to frequency deviations, generators must adjust their generating units' output away from the optimal set point, which is typically the most efficient operating level for the design of the generating unit.

7.16. Frequent changes in output require adjustments in fuel input and steam flow, leading to thermal and mechanical stresses on key components like turbines, boilers and valves. Over time, these stresses contribute to increased wear and tear, reducing equipment lifespan and increasing maintenance costs.

7.17. The further a generating unit is required to move from its optimal operating point, the greater the physical and operational stress on the plant. This can lead to increased maintenance requirements, reduced efficiency, and higher operating costs over time.

7.18. Setting a maximum permitted dead band would reduce disproportionate wear and tear on some generators by sharing the burden across more generating stations. The power system would be able to respond to frequency deviations with smaller, more gradual adjustments from individual generating units.

7.19. The Authority is aware that with a uniform maximum permitted dead band, some technology types with quicker response rates may still take on a disproportionate burden. The Authority is considering undertaking additional work on this in the near future, looking at ramp rates and droop settings for generating stations.

Case study: Reducing the maximum permitted dead band in the Australian National Electricity Market

7.20. The Australian National Electricity Market (NEM) was established in 1998 with a maximum dead band of ±0.15Hz, which aligned with the normal operating band for frequency (normal band) of ±0.15Hz. Generators were not required to respond within the normal band, as it was believed that market-based frequency control ancillary services would efficiently incentivise frequency management.

7.21. As the amount of inverter-based resources increased in the NEM, frequency performance deteriorated. This was due to:

(a) The absence of mandatory primary frequency response (ie, requiring generators to provide governor response / frequency control system response). Many generators withdrew active governor response by widening their governor dead bands or installing secondary control systems that counteracted mechanical governor response. This was done to reduce wear and tear costs.

(b) Financial incentives discouraging frequency response. The frequency control ancillary services framework incentivised generators to strictly follow dispatch targets rather than provide frequency management during normal operation.

7.22. To address the frequency deterioration issue, the NEM's frequency management framework was reformed. Three key changes were implemented:

(a) Mandatory primary frequency response requirements – generators were required to comply with new primary frequency response requirements, including a maximum permitted dead band.

(b) Removal of financial disincentives – amendments were made to remove the financial cost generators faced if providing frequency management under the ‘causer pays’ framework.

(c) Review of long-term incentive structures – future mechanisms were considered to encourage ongoing frequency management.

7.23. As part of these changes, in March 2020, the maximum dead band in the NEM was reduced from ±0.15Hz to ±0.015Hz, requiring generators to respond to frequency deviations much sooner.

7.24. The normal band remained unchanged at ±0.15Hz, distinguishing the dead band for mandatory primary frequency response from the normal band. This adjustment significantly improved system responsiveness to smaller frequency deviations, and strengthened the stability of the grid.

Impact of narrowing the maximum permitted dead band in the NEM

7.25. Between 2015 and 2020, the NEM experienced a deterioration in system frequency. This was attributed to generators modifying their control systems to desensitise active power response to deviations from 50Hz. As a result, aggregate system frequency responsiveness declined.

7.26. The introduction of mandatory primary frequency response in 2020, including the narrower dead band of ±0.015Hz, reversed this trend. From 2021 onwards system frequency was significantly improved, demonstrating the effectiveness of the tighter dead band requirements.

Generator response when AEMO lost visibility of its SCADA system

7.27. Unlike market-based frequency control ancillary services that rely on centralised dispatch signals, primary frequency response operates in real time based on local frequency measurements. Therefore, generators with narrow dead bands are still able to provide autonomous frequency management should centralised dispatch signals be compromised.

7.28. On 24 January 2021, the Australian Energy Market Operator (AEMO) suffered an internal service failure of its SCADA system resulting in AEMO losing visibility across all NEM regions for approximately 55 minutes. However, the power system remained in a secure operating state for the duration of this time. Frequency was well maintained throughout the incident due to the primary frequency response of generators.

7.29. This event served to highlight the importance of wide participation in frequency management. A diverse set of generating units / stations responding to frequency deviations helps to maintain system stability even when central control systems are compromised.

How the NEM dealt with generation types unable to comply with a maximum dead band of ±0.015Hz

7.30. Generators unable to meet the ±0.015Hz dead band in the NEM due to technical constraints were permitted to apply for exemptions or variations. AEMO was responsible for assessing and approving these applications based on the specific technical limitations of the generating system.

7.31. By allowing targeted exemptions and variations, AEMO ensured that most generators contributed to frequency control while accommodating technical constraints where necessary.

Our proposed dead band of ±0.1Hz is wider than in the NEM

7.32. The Authority proposes a dead band of ±0.1Hz, which is more than six times wider than the ±0.015Hz requirement in the NEM. The Authority's view is that a permitted maximum dead band of ±0.1Hz would provide a good balance between improving the regulation of system frequency within the normal band and not imposing significant compliance challenges on new generation. The reason for our view is that generation equipment imported for use in New Zealand will typically also be in use in Australia (geothermal technology excepted). Therefore, generation technology coming into New Zealand will typically be capable of complying with a narrower dead band (±0.015Hz) than what we are proposing.

7.33. The system operator has concluded from a system study[28] that a permitted maximum dead band that is narrower than ±0.1Hz would be likely to further improve performance, however it would be subject to diminishing returns. In addition, the Authority considers it is likely that more generators would be unable to comply with a narrower dead band.

7.34. The Authority considers existing generating units should have to meet the ±0.1Hz dead band requirement unless this is not possible for technical reasons. Permitting existing generating units that can operate within ±0.1Hz to maintain dead band settings wider than ±0.1Hz raises concerns about potential degradation in frequency management, as was observed in the NEM between 2015 and 2020.

7.35. We propose to adopt a similar approach to the NEM in relation to generating units that are unable to meet the ±0.1Hz dead band requirement due to technical constraints. That is, a generator would need to apply to the system operator for a dispensation.

7.36. We consider relying on the dispensations process to be more appropriate than permitting all legacy assets with a dead band wider than ±0.1Hz to not have to comply with the dead band. The reason is that there may be existing generating units with dead bands outside ±0.1Hz but which can operate within ±0.1Hz.

7.37. Having said this, and as discussed under the first proposed Code amendment, dispensations are not costless and we do not want to impose these costs on participants unnecessarily. If it was going to be impossible for one or more generation technologies to comply with the proposed ±0.1Hz dead band, the Authority would be open to an alternative to dispensations. One option may be to include a permanent exclusion for the technology in the Code, as was the case until recently for wind generation in respect of periodic testing.

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[28] See Appendix D of our June 2024 consultation paper.

7.38. The Authority welcomes feedback from submitters on this point.

Proposed Code amendments

7.39. The Authority proposes to amend clause 5 of Technical Code A of Schedule 8.3 of the Code to set a permitted maximum dead band beyond which a generating unit would have to contribute to frequency management and frequency support. This obligation would apply to existing and new generating units.

7.40. The Authority considers that placing the new requirement into clause 5(1)(c) of Technical Code A of Schedule 8.3 is the most appropriate location because a dead band is a setting that is applied to a generating unit's speed governor and/or frequency control system. The new requirement would flow through into the clauses containing frequency-related asset owner obligations in the following manner:

(a) Clause 8.17 requires each generator to ensure that their assets contribute to frequency management in accordance with the technical codes.

(b) Clause 1 of Technical Code A of Schedule 8.3 establishes the overarching obligation for asset owners to operate their assets in a manner that enables the system operator to plan to comply, and to comply, with its principal performance obligations.

(c) Clause 5 of Technical Code A of Schedule 8.3 contains the specific requirements for generators, and subclause (1)(c) provides the requirements for a generating unit's speed governor and/or frequency control system.

7.41. The Authority proposes to amend clause 5 of Technical Code A of Schedule 8.3 as follows:

5 Specific requirements for generators

(1) Each **generator** must ensure that**—**

(a) each of its **generating units**, and its associated **control systems**,**—**

(i) supports the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; and

(ii) is able to **synchronise** at a stable frequency within the frequency range stated in the **asset capability statement** for that **asset**; and

(b) the rate of change in the output of any of its **generating units** does not adversely affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations**. The rate of change must be adjustable to allow for changes in **grid** conditions; and

(c) each of its **generating units** has a speed governor and/or frequency **control system** that**—**

(i) provides stable performance with adequate damping; and

(ii) has an adjustable droop over the range of 1% to 7%; and

(iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics; and

(iv) operates with a dead band not exceeding ±0.1Hz; and

(d) appropriate speed governor and/or frequency **control system** settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The performance of the **generating unit** is then assessed by measurements from **system tests** and final settings are then applied to the **generating unit** before making it ready for service after those final settings are agreed between the **system operator** and the **generator**. An **asset owner** must not change speed governor and/or frequency **control system** settings without **system operator** approval.

(1A) The requirement in subclause (1)(c)(iv) only applies from the time of the next periodic test of the **generating unit** following the commencement of that subclause.

…

8. Code amendment proposal 2 regulatory statement

Objectives of the proposed amendment

8.1. The objective of the proposed Code amendment is to better enable the system operator to maintain frequency within the normal band (49.8–50.2Hz) by setting a maximum permitted dead band. This will improve the responsiveness of the power system to frequency fluctuations, and better enable the system operator to manage the system frequency.

The proposal is consistent with our main statutory objective

8.2. The Code amendment proposal is consistent with the Authority's main statutory objective, in particular the reliability limb and the efficient industry operation limb.

8.3. The proposal promotes reliable supply by the electricity industry, by requiring generating stations to support frequency management sooner. This is expected to:

(a) improve the quality of frequency (ie, better keep frequency nearer to 50Hz)

(b) strengthen the resilience of the power system by ensuring generating stations respond more promptly to frequency deviations.

8.4. The proposal is expected to promote the efficient operation of the electricity industry by reducing disproportionate wear and tear on some generators, by sharing the burden across more generating stations. Currently, there is a reliance on a relatively small number of generating stations to help the system operator manage frequency within the normal band.

8.5. We expect the proposal will also promote the efficient operation of the electricity industry by deferring the need for additional MFK ancillary service with a relatively higher cost than more generating units operating with a dead band of ±0.1Hz.

An evaluation of the costs and benefits of the proposed amendment

Summary of main benefits and costs

8.6. The main benefits of the proposed amendment are deferring the need for additional MFK ancillary service, reduced wear and tear costs for some generators, improved frequency quality, and improved power system resilience.

8.7. The main costs of the proposal are the dispensation costs for some generators that lack the inherent capability to comply, and the minor costs associated with control system changes and periodic testing.

8.8. Table 5 summarises the main identified benefits and costs of Code amendment proposal 2. The Authority considers that the benefits of the proposal materially outweigh the costs of the proposal.

Table 5: Summary of identified benefits and costs of Code amendment proposal 2

Category	Description
Benefits	Deferring the need for additional MFK ancillary service
	Improved frequency quality
	Improved power system resilience
	Reduction in disproportionate wear and tear costs for some generators
Costs	Dispensations for generating stations that lack the inherent capability to comply
	Control system changes
	Periodic testing

The proposal will reduce frequency keeping costs

8.9. Wind and solar photovoltaic generation is intermittent and variable due to the nature of the fuel source. As more of this generation is introduced onto the power system, the existing frequency keeping band of ±15 MW will become insufficient to manage frequency.

8.10. We expect wind and solar photovoltaic generation will displace existing synchronous generation which has the ability to better support regulation of frequency due to governor / frequency control system response. Wind and solar photovoltaic generation can reduce output in response to increasing frequency, but can't increase output due to decreasing frequency unless it either operates below its full capacity or it co-locates a BESS onsite. This will place a greater reliance on the frequency keeping service.

8.11. The total frequency keeping cost over the 12 months ending 30 June 2024 was $12.1m[29]. While it is difficult to quantify the financial impact of dead band settings on frequency keeping requirements, imposing a permitted maximum dead band would likely reduce the amount of frequency keeping capacity that the system operator needs to procure.

8.12. To illustrate the potential scale of these costs, an increase in the frequency keeping band driven by the growing share of wind and solar photovoltaic generation could result in additional costs of approximately $800,000 per year for each 1MW increase across both islands. This estimate is based on a proportional increase from the current cost of maintaining 15MW in each island

[29] Frequency keeping | Transpower

8.13. This figure is intended to highlight the potential materiality of the cost rather than serve as a precise forecast. Actual costs may vary depending on market conditions and the system operator's future procurement approach.

8.14. The proposal would not eliminate the need to widen the MFK band in the future. We expect the MFK band will eventually need to be adjusted regardless of whether or not a maximum permitted dead band is set in the Code. However, the proposal will reduce the pressure on the frequency keeping band in the future.

8.15. After undertaking power system studies, the system operator has concluded that introducing an appropriate maximum permitted dead band would improve the management of system frequency. This could help maintain the effectiveness of the current MFK band of ±15MW, though the extent of this impact would depend on broader system conditions and future changes in generation.

8.16. Implementing a maximum dead band of ±0.1Hz is expected to incur relatively minor costs for most generators, as it primarily involves adjusting control settings. These adjustments are generally straightforward and do not require significant investment or operational changes. While some generators have expressed concerns about potentially increased wear and tear costs associated with smaller dead bands, these costs are not expected to outweigh the broader system benefits.

8.17. In contrast, if such a dead band requirement were to not be implemented, the system operator may need to procure additional MFK ancillary service to maintain system stability. This procurement can be costly and is likely to lead to higher overall costs for the industry relative to the proposal. Therefore, setting a maximum permitted dead band would enhance system reliability while also serving as a cost-effective means for reducing the need to procure additional frequency keeping.

The proposal may assist in avoiding sub-optimal operation of some electrical equipment

8.18. For consumers, more frequency variability within the normal band might cause their electrical equipment to operate sub-optimally. Therefore, to the extent that Code amendment proposal 1 assists in reducing frequency variability over time, the proposal may lessen the possibility of this economic cost for consumers.

The costs of the proposal are expected to be relatively minor

8.19. The primary cost associated with implementing a maximum permitted dead band is related to control system adjustments. For most generators, compliance would simply require updating a control setting within existing control systems. This change is straightforward and immaterial, particularly for modern generators that already have configurable frequency response settings.

8.20. Periodic testing requirements are also not expected to impose material costs. The frequency response of generators is already assessed as part of the existing periodic testing regime, meaning no significant additional testing burden would be introduced.

8.21. Another consideration is the impact on wear and tear costs for generators providing frequency response, which is difficult to quantify but is expected to be minor. However, while some generators would be faced with an increase in wear and tear costs if they are currently operating with a dead band that is outside the proposed range, other generators would have a reduction in their wear and tear costs as more generating stations share the burden.

8.22. The main exception is geothermal generation, which may struggle to comply with a permitted maximum dead band of ±0.1Hz due to the inherent characteristics of the generating technology commonly used. However, the owners of these generating stations would be able to apply for a dispensation if compliance was impractical.

An evaluation of alternative means of achieving the objectives

8.23. As discussed in section 4, the Authority, working in particular with the Common Quality Technical Group and system operator, has identified and evaluated a range of alternative options. These options were described in our June 2024 consultation paper *Addressing more frequency variability in New Zealand's power system*, along with the assessment of each option. That assessment is adopted and incorporated into this regulatory statement and is summarised in the paragraphs below. The Authority does not consider that there have been any changes to the underlying circumstances in the industry since that earlier consultation that materially changes any part of that analysis. The Authority's responses to submissions on the preferred option and the alternative options as set out in the June 2024 consultation paper is set out above.

8.24. A new capability market for frequency support, as supported by several submitters on our June 2024 consultation, may be a credible alternative. However, the long development and implementation timeframe means this alternative would not help address the identified problem for several years. The Authority is focused, at least for now, on solutions that deliver benefits in the shorter term rather than the medium to long term. As discussed earlier in this paper, this alternative may be considered at a later date, as part of another Authority workstream.

8.25. Introducing a maximum permitted dead band of ±0.025Hz was considered by the Authority in 2014 to enhance frequency management. This proposal was based on a 2011 system operator study that modelled the effects of various dead bands (0.025Hz, 0.05Hz, 0.1Hz) on the total response of all generating units to a frequency deviation within the normal band, and the stability of generating units' governors. The study indicated that the power system's response to frequency deviations would not be unduly affected by a small maximum dead band, and that it would have minimal impact on governor stability. However, feedback from generators suggested that a ±0.025Hz dead band was too narrow, and concerns that such a narrow dead band would necessitate significant capital expenditure and operating costs ultimately led to the proposal not being implemented at the time.

8.26. The Authority has considered technology-based dead bands. These could theoretically reduce operating and maintenance costs by aligning requirements with each technology's capabilities. They could also reduce or eliminate applications to the system operator for dispensations, and the associated transaction costs (see the discussion in paragraphs 5.58 – 5.59.

8.27. However, the Authority is concerned this approach could distort investment decisions and operational practices. Additionally, varying dead bands by technology could complicate compliance monitoring and potentially affect the reliability of frequency response.

8.28. Procuring additional frequency keeping services under the status quo may be an alternative. However, we consider the benefit to the power system would be lower than under the proposed amendment. The response of governors / frequency control systems is one of the fastest acting frequency management mechanisms on our power system. This response acts in the first instance to limit system frequency changes due to imbalances between electricity demand and supply, and is an essential part of normal frequency management.

8.29. Yet another alternative may be widening the normal band of 49.8–50.2Hz. However, as explained in Appendix A of our June 2024 consultation paper, this option was not included in the short list of options after being assessed against the evaluation criteria. Feedback received from submitters on our June 2024 consultation paper has not changed the Authority's view on that assessment.

8.30. For the reasons above, and as set out in the June 2024 consultation paper, the Authority prefers the option proposed in this paper.

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

8.31. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to direct dealings between industry participants and these consumers.

8.32. Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

8.33. The Authority considers that Code amendment proposal 2 is necessary or desirable to promote reliability and efficiency in the electricity industry. By setting a maximum permitted dead band, the proposal will mean that more generating stations contribute to managing system frequency within the normal band of 49.8–50.2Hz. This will improve the power system's responsiveness to frequency deviations, and reduce the amount of additional and relatively higher cost frequency-keeping services that would otherwise need to be procured.

The proposed amendment complies with section 17(1) of the Act

8.34. Under section 17(1) of the Act, the Authority in performing its functions, must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister of Energy. Table 6 below sets out our consideration of the Government Policy Statement on Electricity.

Table 6: Consideration of the proposed amendments against the Government Policy Statement on Electricity

Clause	Consideration
2. The Government expects the electricity system to deliver reliable electricity at lowest possible cost to consumers. It should serve the interests of all electricity consumers, including through the provision of sufficient electricity infrastructure to ensure security of supply and avoid excessive prices.	The proposal aligns with the Government Policy Statement as it: • strengthens the reliability and resilience of the power system. It achieves this by enhancing the system operator's ability to comply with its principal performance obligations, by improving the responsiveness of the power system to frequency fluctuations. • is expected to lead to overall cost savings by reducing the amount of ancillary services that need to be procured by the system operator, thereby improving economic efficiency.
8. The Government's role is to ensure clear and consistent regulatory settings, reflected in market rules with robust compliance monitoring and enforcement, that enable an efficient market anchored by accurate price signals, and effective risk management tools and competition.	The proposal aligns with the Government Policy Statement as it promotes clear and consistent regulatory settings across a broader range of industry participants, via rules that have robust monitoring and enforcement provisions.
32. The Electricity Authority is expected to work collaboratively with other agencies across the wider regulatory regime, acknowledging the scope of each agency's remit.	The Authority has collaborated with other agencies during the policy development phase and will continue to collaborate as applicable through any implementation.

The Authority has given regard to the Code amendment principles

8.35. When considering amendments to the Code, the Authority is required by our Consultation Charter to have regard to the following Code amendment principles, to the extent that the Authority considers they are applicable.

8.36. Table 7 describes the Authority's regard for the Code amendment principles in the preparation of Code amendment proposal 2.

Table 7: Regard for Code amendment principles

Principle	
1. Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	The problem definition is set out in section 3 of this paper. An increasing amount of variable and intermittent generation is likely to cause more variability in frequency within the normal band, which is likely to be exacerbated over time by decreasing system inertia. More frequency variability is likely to impose economic costs on consumers by: • causing electrical equipment to operate sub-optimally • increasing the costs associated with the system operator managing the power system frequency.
2. Costs and benefits are summarised	The extent to which the Authority has been able to estimate the proposal's net benefits and efficiency gains is set out in the evaluation of costs and benefits earlier in this section. The proposal's main benefits are that it will better enable the system operator to manage the power system's frequency by improving the responsiveness of the power system to frequency fluctuations, thereby reducing the likelihood of frequency excursions outside the normal band and the risk of an AUFLS block being tripped. The proposal is also expected to defer the need for additional MFK ancillary service, and reduce disproportionate wear and tear that is currently being imposed on some asset owners' generating units. The costs associated with the proposal are expected to be relatively minor, however dispensations may be needed for some generating stations that lack the inherent capability to comply with the proposal.

Q2.1 Do you consider there to be any type of generation technology that cannot, and never will be able to, comply with a dead band of ±0.1Hz? Please explain your answer.

Q2.2 Do you support the Authority's proposal to amend the Code to specify a permitted maximum dead band of ±0.1Hz, beyond which a generating station must contribute to frequency management and support?

Q2.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.

Q2.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.

Q2.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?

Q2.6 Do you have any comments on the drafting of the proposed amendment?

Appendix A Format for submissions

Submitter	

Questions	Comments
Q1.1 Do you support the Authority’s proposal to amend the Code to require smaller generating stations to comply with frequency-related asset owner performance obligations?	
Q1.2 Do you consider the ‘legacy clause’ provisions in the Code amendment proposal should apply to a generating station for a finite period of time (eg. 10 years)? Please explain your answer.	
Q1.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.	
Q1.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010.	
Q1.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?	
Q1.6 Do you have any comments on the drafting of the proposed amendment?	

Q2.1 Do you consider there to be any type of generation technology that cannot, and never will be able to, comply with a dead band of ±0.1Hz? Please explain your answer.	
Q2.2 Do you support the Authority’s proposal to amend the Code to specify a permitted maximum dead band of ±0.1Hz, beyond which a generating station must contribute to frequency management and support?	
Q2.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.	
Q2.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010.	
Q2.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?	
Q2.6 Do you have any comments on the drafting of the proposed amendment?	

Appendix B Proposed Code amendments

B.1. This appendix sets out the Code amendments the Authority has decided to make in accordance with the decisions set out in the main body of this document.

B.2. Proposed amendments to the Code are displayed as follows:

a. text or formatting is red underlined if it is to be added to the Code

b. text or formatting is shown in red ~~strikethrough~~ if it is to be deleted from the Code.

Part 1
Preliminary provisions

…

1.1 Interpretation

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

…

~~**maximum export power** means the maximum **active power** exported into the **local network** or **embedded network** at an **ICP** of a **distributed generator**, and is equal to —~~

~~(a) the **nameplate capacity** of the **distributed generation** minus the minimum load at the **point of connection**; or~~

~~(b) the power export limit imposed by an active export control device~~

maximum export power means, in respect of a **generating plant**, the lesser of**—**

(a) the **nameplate capacity** of the **generating plant** minus the minimum load at its **point of connection**; or

(b) the power export limit imposed by an **active power** export control device

…

Part 8
Common quality

…

8.21 Excluded generating stations

(1) For the purposes of—

(a) clauses 8.17, 8.19, ~~8.25D,~~ and the provisions in **Technical Code** A of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** that has a **maximum export power** of less than 10 **MW**~~exports less than 30 **MW** to a **local network** or the **grid**~~, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.17, 8.19, ~~8.25A, and 8.25B~~ and the relevant provisions in **Technical Code** A of Schedule 8.3; and

(b) clause 8.25D, an **excluded generating station** means a **generating station** that has a **maximum export power** of less than 30 **MW**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.25A and 8.25B.

(2) Whether likely to be **an excluded** ~~**generation**~~ **generating station** or not, a **generator** who is planning to connect to the **grid** or a **local network** a **generating unit** with rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.) capacity) must provide the **system operator** with written advice of its intention to connect together with other information relating to that **generating unit** in accordance with clause 8.25(4).

(3) A **generating station** that was an **excluded generating station** immediately before 1 July 2026 that would no longer be an **excluded generating station** due to the commencement of the [name of the amending instrument] continues to be an **excluded generating station** if—

(a) it is not able to comply, without modification, with one or more of the requirements it would be subject to if it was no longer an **excluded generating station**; and

(b) the **asset owner** of the **generating station** updates the **asset capability statement** for the **generating station** to record that this subclause applies to the **generating station**.

(4) Subclause (3) ceases to apply in respect of a **generating station** from the date—

(a) a modification is made to the **generating station** that means it is able to meet all the requirements it would be subject to if it was not an **excluded generating station**; or

(b) the **generating station's maximum export power** increases above its **maximum export power** immediately before 1 July 2026.

(5) An **asset owner** must, as soon as practicable, update the **asset capability statement** for a **generating station** to record when subclause (3) ceases to apply to the **generating station**.

(6) The **system operator** must **publish** and maintain a list of **generating stations** to which subclause (3) applies.

…

Schedule 8.3
Technical codes

Technical Code A – Assets

…

5 Specific requirements for generators

(1) Each **generator** must ensure that—

(a) each of its **generating units**, and its associated **control systems**,—

(i) supports the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; and

(ii) is able to **synchronise** at a stable frequency within the frequency range stated in the **asset capability statement** for that **asset**; and

(b) the rate of change in the output of any of its **generating units** does not adversely affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations**. The rate of change must be adjustable to allow for changes in **grid** conditions; and

(c) each of its **generating units** has a speed governor and/or frequency **control system** that—

(i) provides stable performance with adequate damping; and

(ii) has an adjustable droop over the range of 1% to 7%; and

(iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics; and

(iv) operates with a dead band not exceeding ±0.1Hz; and

(d) appropriate speed governor and/or frequency **control system** settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The performance of the **generating unit** is then assessed by measurements from **system tests** and final settings are then applied to the **generating unit** before making it ready for service after those final settings are agreed between the **system operator** and the **generator**. An **asset owner** must not change speed governor and/or frequency **control system** settings without **system operator** approval.

(1A) The requirement in subclause (1)(c)(iv) only applies from the time of the next periodic test of the **generating unit** following the commencement of that subclause.

…