Part 8 Code amendment proposal – Part 1

Consultation paper

1 October 2024

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 by providing a solid regulatory foundation to enable the potential of our future power system to be unlocked, delivering better outcomes for consumers.

Our Future Security and Resilience (FSR) programme is a multi-year work programme that seeks to ensure New Zealand's power system remains secure and resilient as the country transitions towards a lower emissions economy.

The highest priority activity in the FSR programme is a review of the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). The review's purpose is to ensure these requirements enable evolving technologies, particularly inverter-based resources, such as wind generation, solar photovoltaic generation and battery energy storage systems, in a manner that is consistent with the Authority's statutory objectives.

In this paper we are consulting on proposed Code amendments to help address two of seven key issues identified in the review of the Part 8 common quality requirements. Those two issues are:

- Network owners and 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.
- The Code is missing some terms that would help enable emerging or new technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies.

This consultation paper presents an initial set of Code amendment proposals forming part of the review of the Part 8 common quality requirements. At a later stage in the review process the Authority will consult on:

- additional Code amendment proposals to help address the above two issues
- Code amendment proposals to help address the remaining five common quality issues.

By adopting a staged approach, the Authority can implement more dynamic and fast-paced solutions to mitigate the immediate challenges facing evolving technologies, while carefully considering solutions to more complex and longer-term challenges. This approach ensures better outcomes for consumers by addressing potential barriers for emerging technologies in a timelier manner.

Addressing common quality issues aligns with our statutory objectives

As noted above, the Authority wants the Code's common quality requirements to enable evolving technologies, particularly inverter-based resources. 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.

We want to address the key common quality issues that have been identified, in a manner that promotes reliability of electricity supply for the long-term benefit of 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.

Your feedback is welcomed

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

Next steps beyond this consultation

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 quarter of 2025.

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1. Introduction

What this consultation is about

1.1. This consultation paper sets out proposed Code amendments to help address two key common quality issues (network information and Code terminology). Code amendments are displayed as follows:

(a) added text or formatting is red underlined

(b) deleted text is black strikethrough.

1.2. Each Code amendment proposal and its associated regulatory statement is set out in a separate section of this paper. Each regulatory statement contains a statement of the objectives of the proposed Code amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objective(s) of the proposed amendment.

1.3. 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), which 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).

1.4. We have assessed each proposal against the Authority's main objective under section 15(1) of the Act, which is to promote competition in, reliable supply by, and 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. As the additional objective applies only to the Authority's activities in relation to dealings between participants and these consumers, the additional objective does not apply to the Code amendment proposals in this paper.

1.5. A summary of the proposed Code amendments is provided in the table below.

Summary of Code amendment proposals

Proposal no.	Key issue	Identified problem	Proposed solution
FSR-001	Network information	Wind-powered generation units are currently excluded from having to comply with the periodic testing requirements in the Code.	Amend the Code to remove the exclusion for wind-powered generating units from the periodic testing requirements.
FSR-002	Network information	The Code's wording regarding the provision of an asset capability statement may lead to confusion, potentially resulting in embedded generators not using the format specified by the system operator.	Amend the Code to clarify that embedded generators must provide an asset capability statement in the format specified by the system operator.

FSR-003	Code terminology	The current Code definitions and processes for determining the causer of under-frequency events (UFEs) only include generators and grid owners, thereby excluding other potential causers.	Amend the Code to include all potential causers of UFEs.
FSR-004	Code terminology	Inverter-based generation does not have a speed governor. Dispensations or equivalence arrangements must be relied on to avoid non-compliance with the Code requirement for a speed governor.	Amend the Code to use technology neutral terminology by replacing the requirement for a speed governor with a requirement to have a speed governor and/or a frequency control system, which broadens the obligation to apply to both machine-based and inverter-based generating units.
FSR-005	Code terminology	Inverter-based generation does not have an excitation system. Dispensations or equivalence arrangements must be relied on to avoid non-compliance with the Code requirement for an excitation system.	Amend the Code to remove the requirement for an excitation system. A voltage control system would still be required, which is a requirement that can be applied to all generation technologies.
FSR-006	Code terminology	Static var compensators must undergo periodic testing under the Code, but these are not the only devices that provide dynamic reactive power compensation. Other devices are not subject to periodic testing requirements.	Amend the Code to replace the references to static var compensators with dynamic reactive power compensation devices.
FSR-007	Code terminology	There is some ambiguity in the Part 8 requirements that apply to energy storage systems, which is leading to unnecessary transaction costs.	Amend the Code to treat energy storage systems as only generation for the purposes of Part 8.
FSR-008	Code terminology	The definition of generating unit in the Code can be interpreted in different ways, which may lead to inconsistent application of some requirements.	Amend the Code to clarify the definition of generating unit.
FSR-009	Code terminology	The fault ride through requirements in Part 8 of the Code are challenging for some machine-based synchronous generating units to comply with, resulting in unnecessary transaction costs.	Amend the Code to clarify the applicability of the fault ride through requirements to machine-based synchronous generating units.

How to make a submission

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to fsr@ea.govt.nz with 'Consultation paper – Part 8 Code amendment proposal – Part 1' in the subject line.

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

1.8. Please note the Authority intends to publish all submissions we receive. 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).

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

1.10. 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

1.11. Please deliver your submission by 5pm on Tuesday 12 November 2024. 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. Background

The Future Security and Resilience programme

2.1. The Authority's Future Security and Resilience (FSR) programme is a multi-year work programme that seeks to ensure New Zealand's power system remains secure and resilient as the country transitions towards a lower emissions economy. By 'power system' we mean all components of the New Zealand electricity system underpinning the New Zealand electricity market, including generation, transmission, distribution, and consumption (load) assets.

2.2. Electrifying certain sectors, such as transport and industrial processes, is important to New Zealand meeting its 2050 net zero carbon target. The power system needs to both enable and respond to this electrification and resulting increase in electricity demand. A critical challenge is to ensure reliability of supply during the transition, at least cost to consumers.

2.3. The Authority considers evolving technologies, particularly inverter-based resources, to be a key enabler of electrification. Examples of inverter-based resources include wind generation, solar photovoltaic generation, and battery energy storage systems. These technologies will enable consumers to have more choice and flexibility around their electricity use and supply.

2.4. However, the uptake in these technologies will lead to a significant increase in variable and intermittent generation, and an increase in bi-directional electricity flows. These will pose challenges to the co-ordination of New Zealand's power system.

2.5. This is where the FSR programme applies. The Authority wants to address these challenges to promote a reliable electricity supply for consumers. We also want to address these challenges 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.

Reviewing the common quality requirements in Part 8 of the Code

2.6. The highest priority activity in the FSR programme is a review of the common quality requirements in Part 8 of the Code. The review's purpose is to ensure these requirements enable evolving technologies, particularly inverter-based resources, in a manner that is consistent with the Authority's statutory objectives.

2.7. This review is the highest priority activity on the FSR programme because of:

(a) the need to ensure the common quality requirements accommodate and facilitate the opportunities offered by evolving technologies, particularly inverter-based resources

(b) the increasing risk to security and resilience as more distributed generation is installed and bi-directional electricity flows become more prevalent

(c) the increasing risk of investments in evolving technologies bringing about outcomes that are not for the long-term benefit of consumers.

2.8. For the purposes of the review of common quality requirements in the Code, the Authority is defining common quality to apply across all of New Zealand's connected transmission and distribution networks. This is broader than the Code's definition, which defines 'common quality' as relating only to the transmission network. The broader definition being used in the FSR programme acknowledges that various security and resilience challenges and opportunities will be common to the transmission network and distribution networks.

What is 'Common Quality'?

'Common quality' means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons. An example is the frequency of electricity.

2.9. While the focus of this work is on the common quality requirements in Part 8 of the Code, the Authority is aware that a review of these requirements has linkages to other parts of the Code. The Authority is carefully considering these linkages as part of the review of the common quality requirements in Part 8.

2.10. The Authority published an Issues paper in April 2023 which set out seven key issues related to the common quality requirements that the Authority had identified through stakeholder engagement. Following careful consideration of submissions on this paper, our description of the seven key issues is as follows:

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 frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

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.

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.

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.

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

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.

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.

2.11. In June 2024 the Authority published a suite of consultation papers on short-listed options to address the first four common quality issues related to frequency and voltage, and to discuss the fifth key common quality issue related to harmonics.

3. FSR-001: Remove the exclusion for wind-powered generation from periodic testing requirements

The existing arrangements

3.1. Clause 8(2) of Technical Code A of Schedule 8.3 of the Code requires asset owners[1] to carry out periodic testing of their assets in accordance with Appendix B of Technical Code A. This requirement for periodic testing is additional to the requirements on asset owners under clauses 2(6) to 2(8) of Technical Code A, in relation to the commissioning or testing of assets.

Wind generating units are excluded from the periodic testing requirement

3.2. All generating units for which wind is the primary power source (wind generating units) are excluded from the periodic testing requirement.[2]

3.3. The exclusion from periodic testing for wind generating units was made in June 2008, by the then electricity regulator, the Electricity Commission (Commission). At that time, the Commission considered it was premature to require periodic testing for wind turbines. This was for several reasons, all of which related to the testing objectives for wind turbines not being fully developed at the time:

(a) Experience in testing transmission-connected wind turbines in New Zealand was limited.

(b) In the absence of wider practical testing experience, the system operator had not fully developed its guidelines for the testing of wind turbines.

(c) The frequency control capability of modern wind turbines was not used under the market arrangements of the time and the system operator did not model the frequency control characteristics of wind turbines.

(d) It was considered that the asset owner performance obligations (AOPOs) for wind turbines were likely to change as technology developed.[3]

3.4. The Commission acknowledged the periodic testing requirements in Appendix B of Technical Code A might need to be reviewed to account for changes in technology and new types of assets being connected to the transmission network. The Commission noted the system operator's *Companion Guide for Testing of Assets*, which contained guidelines for the testing of assets, was intended to be a

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1 The Code defines 'asset owner' to mean a participant who owns an asset used for the generation or conveyance of electricity and a person who operates such an asset and, in the case of Part 8, includes a consumer with a point of connection to the transmission network (grid). The Code defines 'asset' to mean equipment or plant that is connected to or forms part of the grid and, in the case of Part 8, includes equipment or plant that is intended to become connected to the grid and equipment or plant of an embedded generator.

2 See clause 1(3) of Appendix B of Technical Code A of Schedule 8.3 of the Code.

3 Electricity Commission, 2008, Amendments to Electricity Governance Rules 2003 – Routine Testing of Assets, p. 11 (paragraphs 44–48).

continuously evolving guide.[4] This could be used to accommodate new, albeit non-mandatory, testing requirements prior to the regulator's formal review of the periodic testing rules.[5]

3.5. The Authority considers the review of the common quality requirements in Part 8 of the Code is an appropriate opportunity to review the exclusion of wind generating units from the periodic testing regime.

Problem definition

Wind generating units are excluded from the periodic testing requirement

3.6. The Authority considers the exclusion of wind generating units from the periodic testing requirement in Part 8 of the Code to be no longer appropriate, for three reasons.

3.7. First, the Authority considers the reasons for excluding wind generating units in 2008 are no longer valid in 2024:

(a) There is now ample experience in testing transmission-connected wind turbines in New Zealand.

(b) The system operator has fully developed guidelines for the testing of wind turbines.

(c) The frequency control capability of modern wind turbines can be used under the market arrangements for providing instantaneous reserve, although we understand that no providers are doing this currently. Should the owner of a wind generating station offer to provide instantaneous reserve, the system operator would model the instantaneous reserve characteristics of the wind generating station as part of assessing the offer.

(d) The AOPOs for wind turbines have changed in relation to fault ride through. While further change to the AOPOs is possible in the future, this is not a reason to exclude wind generating units from periodic testing.

3.8. Second, the absence of wind generating units from the periodic testing regime is inconsistent with the objective of the regime, which the Authority considers is to assist asset owners to meet their AOPOs by verifying:

(a) the accuracy of data supplied in asset owners' asset capability statements, and

(b) to the system operator's satisfaction that assets are capable of being operated within the limits stated in their asset capability statements.[6]

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[4] In 2019 the system operator replaced this document with three separate companion guides – one each dealing with the testing of generation assets, transmission network assets, and distribution assets.

[5] Electricity Commission, 2008, Amendments to Electricity Governance Rules 2003 – Routine Testing of Assets, p. 13 (paragraph 58).

[6] *Ibid*, p. 3 (paragraph 7). The Authority recognises that periodic testing of protection assets does not in itself provide useful asset capability information to the system operator. However, the system operator's

3.9. Data provided to the system operator in asset capability statements is an essential input to the dynamic models, market models, and planning studies used by the system operator to plan to comply, and to comply, with its principal performance obligations (PPOs).[7]

3.10. As we noted in our 2023 issues paper:

> *Over time, the performance of wind generating units will change, due to wear and tear and/or changes in performance settings. The system operator needs to update its models of the transmission network to reflect these changes, as part of operating the transmission network safely, reliably, and efficiently.* [8]

3.11. The absence of wind generating units from the periodic testing regime can reduce the confidence of the system operator and asset owners in assets meeting the performance requirements set out in the Code. This can result in the system operator incurring higher-than-necessary costs (eg, procuring higher-than-necessary quantities of instantaneous reserve) to support power system stability.

3.12. Third, the exclusion of wind generating units from the periodic testing regime is also inconsistent with two key principles guiding the Authority's consideration of options to address issues with the common quality arrangements in the Code, particularly Part 8 of the Code. These two principles are:

(a) promoting competitive neutrality amongst technologies and fuels

(b) signalling the full costs and benefits of alternative technologies and fuels providing the required service or output.[9]

3.13. The Code should be neutral as to which technology can deliver a required service or output (eg, reliability, security of supply, voltage support, and frequency keeping) in the most economically and technically efficient manner. The Code should not give a competitive advantage to a generating unit based on its technology, its capacity or its connection type.[10]

3.14. The Code should also ensure, to the extent practicable, that the full benefits and costs of alternative technologies providing a service or output are signalled to interested or affected parties, including costs imposed on other parties.

3.15. The exclusion from periodic testing for wind generating units does not signal the full benefits and costs of this generation technology type and confers a regulatory advantage to it. Under the Code as it stands, only wind generating units are excluded from the periodic testing requirements in Part 8 of the Code.

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ability to meet its principal performance obligations in the Code relies as much on the correct operation of protection systems as it does on the availability of accurate asset capability information.

7 Clauses 7.2A to 7.2D of the Code set out the system operator's PPOs.

8 Electricity Authority, 2023, Future Security and Resilience – Review of common quality requirements in Part 8 of the Code: Issues Paper, p. 46 (paragraph 6.17).

9 Electricity Authority, 2024, Future Security and Resilience – Review of common quality requirements in the Code: Suite of three consultation papers, pp. 16–17.

10 By 'connection type', we mean whether the generating unit is connected to the transmission network, a local distribution network, or a secondary network (eg, an embedded network).

Proposal

Clause 1 (Appendix B, Technical Code A, Schedule 8.3)

3.16. The Authority proposes to remove the exception for wind-powered generating units from periodic testing requirements, by revoking subclause 1(3) of Appendix B of Technical Code A in Schedule 8.3 of the Code.

3.17. The Authority also proposes to insert a transitional provision in the Code. Specifically, we propose to insert a deadline of 31 December 2028 for wind generating units commissioned before 1 January 2016 to complete the applicable periodic tests. This is intended to avoid a bow wave of testing of existing wind generating units that would otherwise need to be tested as soon as the proposed Code amendment took effect – being those units commissioned more than 10 years before the proposed Code amendment's effective date.

3.18. We are proposing not to stagger the obligation (eg, a generator being required to test half of its wind generation by 31 December 2026 and the other half by 31 December 2028). This is to provide generators owning older wind generating units with the maximum flexibility around when they undertake periodic testing.

3.19. We expect these generators will not wait until the last minute to undertake their testing. This is because doing so would run the risk of non-compliance due to resourcing limitations, including within the system operator. (We expect the system operator will monitor these generators' progress with periodic testing and keep them informed of the system operator's ability to support the generators' testing.)

3.20. We propose amending clause 1 as follows:

1 Periodic tests to be carried out

(1) This Appendix sets out periodic tests required for the purposes of clause 8(2) of **Technical Code** A.

(2) Each **asset owner** may be legally required, other than under this Code, to carry out additional tests to ensure that their assets, **including automatic under-frequency load shedding** systems, are safe and reliable.

~~(3) For the purposes of this Appendix, **generating unit** does not include a **generating unit** for which wind is the primary power source.~~

(4) Each **asset owner** with one or more **generating units** commissioned before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.

Q1.1. Do you support the Authority's proposal to apply the periodic testing requirements in Appendix B of Technical Code A of Schedule 8.3 to wind generation? If you disagree, please give reasons and provide alternatives that address the identified problem with wind generation being excluded from the periodic testing requirements.

Q1.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

3.21. The objective of the proposed Code amendment is to ensure all generation technologies are subject to equivalent testing obligations.

Evaluation of the costs and benefits of the proposed amendment

3.22. The proposed Code amendment's primary benefit is promoting the security and resilience of the power system. This is achieved in a couple of ways.

3.23. First, requiring wind generating units to undergo periodic testing to verify their operational capabilities and compliance with performance standards set out in the Code increases the confidence of the system operator and asset owners in wind generating units meeting their AOPOs. This, in turn, reduces the possibility of the system operator incurring higher-than-necessary costs (eg, procuring higher-than-necessary quantities of instantaneous reserve) to support power system stability.

3.24. Secondly, as noted above, data provided to the system operator in asset capability statements is an essential input to the dynamic models, market models, and planning studies used by the system operator to plan to comply, and to comply, with its PPOs. This includes better enabling the system operator to dispatch the appropriate assets and ancillary services necessary to maintain frequency across the power system and voltage stability across the transmission system.

3.25. The proposed Code amendment also promotes competitive neutrality amongst generation technologies. It enables better signalling of the benefits and costs of wind generating units.

3.26. The primary cost of the proposed Code amendment will be applicable testing costs for the owners of wind generating units who are not undertaking voluntary testing to ensure they keep up to date the asset capability statement information they have provided to the system operator.[11]

[11] Clause 2(5) of Technical Code A of Schedule 8.3 requires each asset owner to keep up to date the asset capability statement information they have provided to the system operator.

3.27. Assuming little or no voluntary testing occurs at present, the Authority expects the incremental cost of the proposed Code amendment may be in the range of $750,000 – $1,500,000. This estimate is based on information provided to the Authority informally by industry participants and stakeholders. Key assumptions in this cost estimate are:

(a) Periodic testing of wind generating units will be per plant controller, meaning wind generating unit testing will in effect be per wind farm (generating station).

(b) The periodic testing cost per wind generating station will be approximately $50,000 – $100,000.

(c) Over the first 10 years following the proposed Code amendment, an average of one to two wind generating stations will undergo periodic testing each year.

(d) A 7% discount rate is used to calculate the present value of the cost estimate.

3.28. Although we have not quantified the expected incremental benefits of the Code amendment, the Authority's assessment is that these benefits are likely to be larger than the expected incremental costs. This is consistent with placing periodic testing obligations on all other generation types.

Evaluation of alternative means of achieving the objectives of the proposed amendment

3.29. The Authority considered one alternative option to the proposal, as summarised in the table below:

Alternative options	Reasons not favoured
Create a guideline without a Code amendment.	More complex and cannot be enforced, as compared to the proposal.

Assessment of the proposed Code amendment against section 32(1) of the Act

3.30. The Authority considers the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes reliable supply of electricity to consumers, and the efficient operation of the electricity industry. It does so by ensuring an acceptable level of compliance by wind generation with the AOPOs in Part 8 of the Code and providing the system operator with better data to plan to comply, and to comply, with its PPOs. Additionally, the Authority considers the proposed amendment promotes competition in the electricity industry by removing the existing preferential treatment of wind generating units in relation to periodic testing.

Assessment against Code amendment principles

3.31. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q1.3. Do you agree the proposed Code amendment is preferable to the other option 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.

Q1.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

4. FSR-002: Clarify that embedded generators must provide an asset capability statement in a format specified by the system operator

The existing arrangements

4.1. Technical Code A of Schedule 8.3 of the Code outlines requirements for asset owners which are intended to enable the system operator to plan to comply, and comply, with its PPOs.[12]

4.2. An embedded generator is an asset owner, but only for the purposes of Part 8 of the Code. This is because the Code defines an 'asset owner' as 'a participant who owns an asset used for the generation or conveyance of electricity and a person who operates such an asset and, in the case of Part 8 of the Code, includes a consumer with a point of connection to the grid (transmission network).'[13] The Code defines 'asset' to mean equipment or plant that is connected to or forms part of the grid and, in the case of Part 8, expressly includes 'equipment or plant of an embedded generator'.[14]

4.3. Clause 2(2) of Technical Code A requires each asset owner (including embedded generators) to provide the system operator, at the times specified in the clause, with an asset capability statement and any other information reasonably required by the system operator, to allow the system operator to assess the compliance of each asset or any configuration of assets with the requirements of the AOPOs and technical codes.

4.4. Clause 2(5) of Technical Code A prescribes the requirements for asset capability statements. It says asset capability statements must be provided to the system operator in the form specified by the system operator.

Problem definition

4.5. Clause 2(2) of Technical Code A clearly requires embedded generators, as asset owners for the purposes of Part 8, to provide an asset capability statement to the system operator. However, the Code could be clearer about the form in which embedded generators must provide the information to the system operator.

4.6. Clause 2(5) of Technical Code A states that '[e]ach asset owner must provide the system operator with an asset capability statement in the form from time to time published by the system operator *for each asset that is proposed to be connected, or is connected to, or forms part of the grid*.' This doesn't mention 'equipment or plant of an embedded generator', which is also an 'asset' under the Code.

4.7. As drafted, clause 2(5) of Technical Code A does not specifically say that asset capability statements provided to the system operator by embedded generators

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12 See clause 1 of Technical Code A.

13 See clause 1.1 of the Code.

14 *Ibid*

under clause 2(2) of Technical Code A must be provided in the form specified by the system operator.

4.8. Currently, embedded generators provide asset capability statement information to the system operator in the same form as grid-connected generators. However, the potential exists for embedded generators to provide information to the system operator in some other form. This creates the potential for unnecessary transaction costs and/or operational inefficiencies around the compilation and management of asset capability statement information by the system operator.

4.9. The Code could also be clearer that a generator with a generating unit with rated net maximum capacity less than 1MW does not need to provide the system operator with asset capability statement information.

4.10. Clauses 8.21 and 8.25 of the Code require generators with a generating unit with rated net maximum capacity equal to or greater than 1MW to provide the system operator information that complies with the technical codes or otherwise as the system operator reasonably requests. However, clause 2 of Technical Code A does not mention the 1MW threshold.

Proposal

4.11. The Authority proposes to amend clause 2 of Technical Code A of Schedule 8.3 of the Code to clarify that:

(a) the requirement to provide an asset capability statement to the system operator applies only to generators with a generating unit with rated net maximum capacity equal to or greater than 1MW

(b) the requirement to provide an asset capability statement in the form from time to time published by the system operator applies to embedded generators as well as grid-connected generators (by clarifying that the requirement applies to assets connected directly or indirectly to a local network).

Schedule 8.3 Technical codes

Technical Code A – Assets

...

2 General requirements

…

(2) Each **asset owner** must provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, to allow the **system operator** to assess compliance of its **asset** or any configuration of **assets** with the requirements of the **asset owner performance obligations** and **technical codes** at each of the following times:

…

(2A) For **asset owners** that are **generators**, the obligation to provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, applies only to **generators** with a generating unit with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2).

…

(5) Each **asset owner** must provide the **system operator** with an **asset capability statement** in the form from time to time **published** by the **system operator** for each **asset** that:

(a) is—

(i) proposed to be connected, or is connected to, or forms part of the **grid**~~.~~; or

(ii) proposed to be connected, or is connected directly or indirectly to a **local network**; and

(b) forms part or all of a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2) at the **point of connection** to the **network**.

(5A) The **asset capability statement** must:

(a) include all information reasonably requested by the **system operator** so as to allow the **system operator** to determine the limitations in the operation of the **asset** that the **system operator** needs to know for the safe and efficient operation of the **grid**; and

(b) include any modelling data for the planning studies, as reasonably requested by the **system operator**; and

(c) be updated and reissued to the **system operator** as information and design development progresses through the study, design, manufacture, testing and **commissioning** phases; and

(d) be complete and up to date before the **commissioning** of the **asset**; and

(e) be complete and up to date at all times while the **asset** is—

(i) connected to, or forms part of, the **grid**; or

(ii) connected directly or indirectly to a **local network**.

Q2.1. Do you support the Authority's proposal to amend the Code to clarify that:

(a) embedded generators must provide asset capability statement information to the system operator in the form from time to time published by the system operator, and

(b) the requirement to provide an asset capability statement to the system operator applies only to generators with a generating unit with rated net maximum capacity equal to or greater than 1MW?

Q2.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

4.12. The objective of the proposed Code amendment is to ensure that all asset capability statement information is provided to the system operator in a form published by the system operator from time to time, and that generators with generating units less than 1MW do not provide asset capability statement information unnecessarily. This will reduce the potential for unnecessary operational costs.

Evaluation of the costs and benefits of the proposed amendment

4.13. The primary benefit of the proposed Code amendment is avoiding the potential for unnecessary operational costs for smaller generators and for the system operator.

4.14. The Authority expects the proposed amendment to have negligible incremental costs because embedded generators currently provide asset capability statements in the form published by the system operator from time to time.

Evaluation of alternative means of achieving the objectives of the proposed amendment

4.15. The Authority has not identified an alternative means of achieving the objectives of the proposed Code amendment.

Assessment of the proposed Code amendment against section 32(1) of the Act

4.16. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the efficient operation of the electricity industry, for the long-term benefit of consumers, by reducing the potential for unnecessary operational costs for smaller generators and for the system operator.

Assessment against Code amendment principles

4.17. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q2.3. Do you agree with the proposed Code amendment? 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.

Q2.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

5. FSR-003: Include distributors and energy storage systems as potential causers of under-frequency events

The existing arrangements

5.1. The Code requires the system operator to maintain frequency within 0.4% of 50Hz (ie, 49.8–50.2Hz, defined in the Code as the “normal band”), 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.

5.2. An under-frequency event (UFE) occurs when, within any 60 second period, the frequency falls below 49.25Hz due to a loss of more than 60MW injected into the grid (transmission network). The Code requires the Authority to determine the causer of a UFE and sets out the process for the Authority to make a determination.[15] Once a causer is determined, they must pay an ‘event charge’ to the system operator.

Problem definition

5.3. Clauses 8.60 and 8.61 of the Code use the term “causer”, which is a defined term in clause 1.1 of the Code. This definition only includes generators and grid owners as possible causers of a UFE. The clause 1.1 definition is below:

> **causer**, in relation to an **under-frequency event**, means—
>
> (a) if the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator’s** or **grid owner’s asset** or **assets**, the **generator** or **grid owner**; unless—
>
> (i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator’s asset** or **assets** but another **generator’s** or a **grid owner’s** act or omission or property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or
>
> (ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **grid owner’s asset** or **assets** but a **generator’s** or another **grid owner’s** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**; or
>
> (b) if the **under-frequency event** is caused by more than 1 interruption or reduction of **electricity**, the **generator** or **grid owner** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption or reduction of **electricity**; but

[15] See clauses 8.60 and 8.61 of the Code. The Authority is currently consulting on an unrelated change to the consultation requirements for under frequency events. See Code amendment omnibus four: September 2024

(c) if an interruption or reduction of **electricity** occurs in order to comply with this Code, the interruption or reduction of **electricity** must be disregarded for the purposes of determining the **causer** of the **under-frequency event**.

5.4. Clauses 8.60 and 8.61 also specify that the causer is either a generator or grid owner and set out provisions for calculating event costs and rebates where the causer is a generator or grid owner.

5.5. The process for determining the causer of a UFE was based on a more traditional power system, before the widespread adoption of inverter-based resources and associated changes to the power system. It assumes that energy flows in a single direction, from the generator injecting electricity into the transmission network which then flows through the distribution networks. However, with the increased uptake of inverter-based resources there is an increasing amount of generation (and potentially energy storage systems) embedded within distribution networks.

5.6. With electricity flowing in both directions within the power system and increasingly larger amounts of embedded generation, UFEs can be caused by participants that are not identified under the current Code provisions. In particular, distribution networks and energy storage systems have the potential to trigger a UFE.

5.7. The current requirements do not best promote the Authority's main statutory objective, as they may not impose costs on the causers of all UFEs. The possible misallocation of disincentives impacts the reliability and efficiency of the New Zealand power system.

Proposal

5.8. The Authority proposes to amend the Code to include all potential causers of a UFE. We propose to do this by referring to the action that results in a UFE, including an increase in electricity demand (load), rather than listing the types of participants who could cause a UFE. The proposed changes to the Code are set out below.

5.9. The Authority is not proposing a change to the allocation of availability costs nor a change to the parties receiving a rebate on their availability costs for UFEs (refer to clauses 8.59 and 8.65 of the Code). An availability cost is a cost incurred by the system operator in purchasing and providing instantaneous reserve for a trading period.

5.10. Practically speaking, the Authority's proposed approach means demand (load) UFE causers make no contribution to availability costs but then do not receive any rebate from the payment of event costs for UFEs.

5.11. The reason we are proposing this approach is our expectation that typically UFEs in the future will continue to be caused by generators or by the HVDC owner. We consider this approach to be a more pragmatic and lower cost solution than changing the allocation and rebate methodologies under clauses 8.59 and 8.65 to include demand (load) event causers.

Part 1 Preliminary provisions

1.1 Interpretation

…

causer, in relation to an **under-frequency event**, means—

(a) if the **under-frequency event** is caused by an interruption to or reduction of **electricity** supply, or an increase in **electricity** demand, from a single ~~**generator's** or **grid owner's**~~ **participant's** **asset** or **assets**, the ~~**generator,** or **grid owner**~~ **participant**~~;~~, unless another **participant's** act or omission or property causes the interruption to or reduction of **electricity** supply or the increase in **electricity** demand, in which case the other **participant** is the causer~~—~~

~~(i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's asset** or **assets** but another **generator's** or a **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or~~

~~(ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **grid owner's asset** or **assets** but a **generator's** or another **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**~~; or

(b) if the **under-frequency event** is caused by more than 1 interruption to or reduction of **electricity** supply or increase in **electricity** demand, the ~~**generator** or **grid owner**~~ **participant** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption to or reduction of **electricity** supply or increase in **electricity** demand; but

(c) if an interruption to or reduction of **electricity** supply, or an increase in **electricity** demand, occurs in order to comply with this Code, the interruption to or reduction of **electricity** supply or the increase in **electricity** demand must be disregarded for the purposes of determining the **causer** of the **under-frequency event**

…

8.60 System operator must investigate causer of under-frequency event

(1) The **system operator** must promptly advise the **Authority**~~,~~ and every ~~**generator**, **grid owner** and any other~~ **participant** substantially affected by an **under-frequency event**, that an **under-frequency event** has occurred.

(2) The **system operator** may, by notice in writing to a **participant**, require a **participant** to provide information required by the **system operator** for the purposes of this clause.

(3) A notice given under subclause (2) must specify the information required by the **system operator** and the date by which the information must be provided (which must not be earlier than 20 **business days** after the notice is given).

(4) A **participant** who has received a notice under subclause (2) must provide the information required by the **system operator** by the date specified by the **system operator** in the notice.

(5) Within 40 **business days** of receiving the information, or such longer period as may be agreed by the **Authority**, the **system operator** must provide a report to the **Authority** that includes the following:

(a) whether, in the **system operator's** view, the **under-frequency event** was caused by a ~~**generator** or **grid owner**~~ **participant**, and if so, the identity of the **causer**:

(b) the reasons for the **system operator's** view:

(c) all of the information the **system operator** considered in reaching its view.

…

8.61 Authority to determine causer of under-frequency event

(1) The **Authority** must determine whether an **under-frequency event** has been caused by a ~~**generator or grid owner**~~ **participant** and, if so, the identity of the **causer**.

(2) The **Authority** must **publish** a draft determination that states whether the **under-frequency event** was caused by a ~~**generator or grid owner**~~ **participant** and, if so, the identity of the **causer**.

(3) The **Authority** must give reasons for its findings in the draft determination.

(4) The **Authority** must consult every ~~**generator, grid owner** and other~~ **participant** substantially affected by an **under-frequency event** in relation to the draft determination.

(5) When the **Authority publishes** the draft determination under subclause (2), the **Authority** must give notice to ~~**generators, grid owners**, and other~~ **participants** substantially affected by the **under-frequency event** of the closing date for submissions on the draft determination.

(6) The date referred to in subclause (5) must be no earlier than 10 **business days** after the date of **publication** of the draft determination.

(7) The **Authority** must **publish** submissions received under subclause (4) unless there is good reason for withholding information in a submission.

(8) For the purposes of subclause (7), good reason for withholding information exists if there is good reason for withholding the information under the Official Information Act 1982.

(9) Following the consultation under subclause (4), the **Authority** must **publish** a final determination.

…

8.64 Event costs allocated to event causers where interruption to or reduction of electricity supply

The **event charge** payable by the **causer** of an **under-frequency event** where the cause of the **under-frequency event** is an interruption or reduction of **electricity** (referred to as "Event e" below) must be calculated in accordance with the following formula:

$$EC = ECR * (\Sigma y \text{ (INTye for all y)} - INJ_D)$$

where

EC	is the **event charge** payable by the **causer**
ECR	is $1,250 per **MW**
INJ_D	is 60 **MW**
INTye	is the electric power (expressed in **MW)** lost at point y by reason of Event e (being the net reduction in the **injection** of **electricity** (expressed in **MW)** experienced at point y by reason of Event e) excluding any loss at point y by reason of secondary Event e
y	is a **point of connection** or the **HVDC injection point** at which the **injection** of **electricity** was interrupted or reduced by reason of Event e.

…

8.64A Event costs allocated to event causers where increase in electricity demand

The **event charge** payable by the **causer** of an **under-frequency event** where the cause of the **under-frequency event** is an increase in **electricity** demand (referred to as "Event e" below) must be calculated in accordance with the following formula:

$$EC = ECR * (\Sigma y \text{ (INCye for all y)} - COND)$$

where

EC	is the **event charge** payable by the **causer**
ECR	is $1,250 per **MW**
CON_D	is 60 **MW**
INCye	is the increase of electric power (expressed in **MW)** at point y by reason of Event e (being the increase in the demand for **electricity** (expressed in **MW)** experienced at point y by reason of Event e) excluding any increase or loss of electric power (expressed in **MW**) at point y by reason of secondary Event e
y	is a **point of connection** or the point at which **electricity** is supplied to the **HVDC link** at which an increase in **electricity** demand occurs by reason of Event e.

8.65 Rebates paid for under-frequency events

An **event charge** that has been paid for an **under-frequency event** (referred to as "Event e") under clause 8.64 or under clause 8.64A must be rebated in accordance with the following formula to persons who are allocated **availability costs** in accordance with clause 8.59:

…

…

8.66 Payments and rebates

All costs calculated in accordance with clauses 8.59, ~~and~~ 8.64 and 8.64A are payable by the relevant **participants** to the **system operator**, and all **event charge** rebates calculated in accordance with clause 8.65 are payable by the **system operator** to the relevant **participants**, in accordance with clause 8.69.

…

Q3.1. Do you support the Authority's proposal to amend the definition of 'causer' in clause 1.1 of the Code so that it refers to the action that results in a UFE, including an increase in electricity demand (load), and the consequential amendments to clauses 8.60 to 8.66, including proposed new clause 8.64A?

Q3.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

5.12. The objective of the proposed Code amendment is to ensure that all relevant parties who could potentially cause a UFE are included under the UFE causer provisions in the Code. This is intended to support the system operator's ability to effectively manage and mitigate UFEs.

Evaluation of the costs and benefits of the proposed amendment

5.13. The primary benefit is the allocation of costs associated with a UFE to all potential causers, providing a more efficient incentive on all potential causers, including potential demand (load) causers, to mitigate the likelihood of them causing a UFE.

5.14. The cost to calculate the event cost allocated to a demand (load) causer of a UFE and any other parties is expected to be relatively minor, involving minimal changes to existing systems and processes.

Evaluation of alternative means of achieving the objectives of the proposed amendment

5.15. The Authority considered two alternative options to the proposed Code amendment, as summarised in the table below:

Alternative options	Reasons not favoured
Revise the allocation of availability costs and change the parties receiving a rebate on their availability costs for UFEs.	The expected implementation cost is significantly higher, while the additional incentive on demand (load) to not cause UFEs is not significantly higher.
Review the UFE management framework in the Code.	Requires significant time and resources, which is outside the scope of this project.

Assessment of the proposed Code amendment against section 32(1) of the Act

5.16. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the reliable supply of electricity to consumers and the efficient operation of the electricity industry. The proposed amendment does this by ensuring that all potential causers of under-frequency events, including participants who suddenly increase their demand, are identified and, where appropriate, held accountable, which will incentivise better practices and reduce the likelihood of under-frequency events.

Assessment against Code amendment principles

5.17. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q3.3. 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.

Q3.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

6. FSR-004: Amend the requirement to have a speed governor

The existing arrangements

6.1. The Code places an obligation on generators to make sure that each of their generating units has a speed governor. The Code further specifies requirements for speed governor settings and testing. The purpose of a speed governor is to automatically adjust a generating unit's output in response to changes in system frequency.

6.2. The term 'speed governor' is used in the following clauses of the Code:

(a) clause 1.1(1) – definition of common quality

(b) clause 5(1)(c) of Technical Code A of Schedule 8.3

(c) clause 5(1)(d) of Technical Code A of Schedule 8.3

(d) clause 3 of Appendix B of Technical Code A of Schedule 8.3.

Problem definition

6.3. The term 'speed governor' is technology specific and generally refers to synchronous generating machines. Generating units that use inverters when functioning may not have speed governors, relying instead on other means by which to regulate frequency. Examples include solar photovoltaic generation, battery energy storage systems, and some wind generation.

6.4. Currently, the owners of these inverter-based generating units must apply to the system operator for an equivalence arrangement to avoid non-compliance with the requirement to have a speed governor under Schedule 8.3.[16] The equivalence arrangement shows that the asset owner is complying with their obligations by using other means or assets to regulate frequency. This imposes avoidable administration costs on asset owners to apply for these equivalence arrangements and on the system operator to process and approve these arrangements.

Proposal

6.5. The Authority proposes to amend the Code to use technology neutral terminology that anticipates the use of both machine-based and inverter-based generating units. Specifically, we propose to replace the requirement for a speed governor with a requirement to have a speed governor and/or a frequency control system, which broadens the obligation to apply to both machine-based and inverter-based generating units.

6.6. To implement this proposal, we propose the following changes to the Code:

[16] Noting the reference to 'speed governor' in clause 1.1 of the Code does not impose an obligation on industry participants.

Clause 1.1 – definition of 'control system'

6.7. We propose amending clause 1.1 definition of 'control system' as follows:

> **control system** means equipment that adjusts the output voltage, frequency, active power~~**MW**~~ or **reactive power** (as the case may be) of an **asset** in response to certain aspects of **common quality** such as voltage, frequency, active power~~**MW**~~ or **reactive power**

Clauses 5(1)(c) and 5(1)(d) (Technical Code A, Schedule 8.3)

6.8. We propose amending clauses 5(1)(c) and 5(1)(d) of Technical Code A, Schedule 8.3 as follows:

5 Specific requirements for generators

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

…

(c) each of its **generating units** has a speed governor and/or a 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

(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.

…

Clause 3 (Appendix B, Technical Code A, Schedule 8.3)

6.9. We propose amending clause 3 of Appendix B of Technical Code A, Schedule 8.3 as follows

3 Generating unit ~~governor and speed~~ frequency control systems

Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 must –

(a) test the ~~governor system~~ response of each of its **generating units'** mechanical or analogue speed governors and/or mechanical or analogue frequency **control systems** at least once every 5 years; and

(b) test the ~~governor system~~ response of each of its **generating units'** digital or electro-hydraulic ~~speed governors~~ frequency **control systems** at least once every 10 years; and (ba) unless agreed otherwise with the **system operator**, for **generating units** with inverters test the control settings for each **generating unit's** frequency **control system** within 3 months of a change to the control settings and/or firmware; and

(c) based on the tests carried out in accordance with paragraphs (a), ~~or~~ (b) or (ba), provide a verified set of modelling parameters and governor or frequency **control system** response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the ~~governor~~ frequency **control system**; and

(ii) for **generating units** with a turbine, a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and

(iia) for **generating units** with a power converter, a block diagram showing the mathematical representation of the power converter and its electrical control; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams~~.~~; and

(iv) for **generating units** with inverters, a verified set of control settings and relevant firmware version identifiers for each **generating unit's** frequency **control system**.

Q4.1. Do you support the Authority's proposal to amend clause 1.1 of Part 1 of the Code, and clauses 3, 4 and 5 of Appendix B of Technical Code A of Schedule 8.3, to broaden them to apply to inverter-based generation technologies?

Q4.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

6.10. The objective of the proposed Code amendment is to remove from the Code all technology-specific references to frequency control systems.

Evaluation of the costs and benefits of the proposed amendment

6.11. The benefits of the proposed Code amendment are twofold. Firstly, it would improve the clarity of the obligations in the Code, regardless of the generating technology used. Secondly, it would remove administrative costs currently faced by the system operator and generators with inverter-based resources. There would no longer be the need for generators to apply for equivalence arrangements and for the system operator to process and approve these arrangements.

6.12. We expect the cost of implementing the proposed Code amendment to be minimal on the basis that it largely aligns with the operating practices of generators with inverter-based generating units subject to periodic testing.

Evaluation of alternative means of achieving the objectives of the proposed amendment

6.13. The Authority considered one alternative option to the proposed Code amendment, as summarised in the table below:

Alternative options	Reasons not favoured
Creating a new term to replace the term 'speed governor'.	The term 'frequency control system' was favoured over other possible terms since it builds on the term 'control system' that is already defined in the Code.

Assessment of the proposed Code amendment against section 32(1) of the Act

6.14. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the efficient operation of the electricity industry. The amendment does this by improving the clarity of obligations in the Code, regardless of the technology used, and reducing unnecessary administrative burden on the system operator and generators.

Assessment against Code amendment principles

6.15. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q4.3. Do you agree the proposed Code amendment is preferable to the other option 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.

Q4.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

7. FSR-005: Amend the requirement to have an excitation system

The existing arrangements

7.1. The Code requires each generator to ensure that each of its generating units connected to the grid (transmission network) is equipped with an excitation and voltage control system. The Code specifies settings and testing requirements for excitation and voltage control systems.

Problem definition

7.2. The Code references to ‘excitation system’ were written when the vast majority of electricity generation came from synchronous machines. This is changing, with more inverter-based resources connected to the power system. The Code’s requirements and terminology need to adapt, to apply to both synchronous machines and inverter-based resources.

7.3. The requirement for an excitation system specifically refers to synchronous machines and is not applicable to electricity generation that uses inverters. Inverter-based generation does not have excitation systems but instead has other systems in place to control voltage. Examples of this type of generation include solar photovoltaic generation, battery energy storage systems, and some wind generation.

7.4. As a result, owners of inverter-based generation need to rely on equivalence arrangements to ensure they comply with the Code requirement to have an excitation system. This imposes avoidable administration costs on the asset owner to apply for these equivalence arrangements and on the system operator to process and approve these arrangements.

Proposal

7.5. The Authority proposes to amend the Code to replace the requirement for an excitation system with a requirement that is agnostic to the generating technology being used. The requirement for a ‘voltage control system’ can be applied to all generation technologies.

7.6. Removing the requirement for an excitation system would remove the need for inverter-based generators to rely on dispensations or equivalence arrangements to ensure they comply with the Code.

7.7. The terms ‘excitation’ and ‘exciters’ appears in several clauses in the Code. We propose to amend them as follows.

Clause 1.1 – definition of ‘control system’

7.8. We propose amending clause 1.1 definition of ‘control system’ as follows:

> **control system** means equipment that adjusts the output voltage, frequency, **MW** or **reactive power** (as the case may be) of an **asset** in response to certain aspects of **common quality** such as voltage, frequency, **MW** or **reactive power**~~, including speed governors and exciters~~

Clause 5(2)(a) (Technical Code A, Schedule 8.3)

7.9. We propose amending clause 5(2)(a) of Technical Code A, Schedule 8.3 as follows:

5 Specific requirements for generators

…

(2) Each **generator** must ensure that each of its **generating** units connected to the **grid** is equipped with—

(a) a ~~an excitation and~~ voltage ~~control system~~ **control system** with a voltage set point that is adjustable over the range of voltage set out in clause 8.23 and operates continuously in the voltage control mode when **synchronised**; and

…"

Clause 5 (Appendix B, Technical Code A, Schedule 8.3)

7.10. We propose amending clause 5 of Appendix B of Technical Code A, Schedule 8.3 as follows:

5 Generating unit voltage response and control

Each **generator** with a **point of connection** to the **grid** must—

(a) test the modelling parameters and voltage response of each of its **generating units'** analogue ~~excitation~~ voltage **control systems** at least once every 5 years; and

(b) test the modelling parameters and voltage response of each of its **generating units'** digital ~~excitation~~ voltage **control systems** at least once every 10 years; and

(ba) unless agreed otherwise with the **system operator**, for **generating units** with inverters test the control settings for each **generating unit's** voltage **control system** within 3 months of a change to the control settings and/or firmware; and

(c) based on the tests carried out in accordance with paragraphs (a), ~~or~~ (b) or (ba), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the ~~automatic~~ voltage **control system** ~~regulator~~; and

~~(ii) a block diagram showing the mathematical representation of the exciter; and~~

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iv) for **generating units** with inverters, a verified set of control settings and relevant firmware version identifiers for each **generating unit's** voltage **control system**.

Clause 11 (Appendix B, Technical Code A, Schedule 8.3)

7.11. We propose amending clause 11 of Appendix B of Technical Code A, Schedule 8.3 as follows:

11 Grid owner synchronous compensators

Each **grid owner** must –

(a) test each of its synchronous compensators' analogue and electromechanical ~~excitation~~ voltage **control** **systems** at least once every 5 years; and

(b) test each of its synchronous compensators' digital ~~excitation~~ voltage **control** **systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including –

  (i) a block diagram showing the mathematical representation of the ~~automatic~~ voltage **control system** ~~regulator~~; and

  ~~(ii) a block diagram showing the mathematical representation of the exciter; and~~

  (iii) a detailed functional description of the ~~excitation~~ voltage **control** **system** in all modes of control; and

  (iv) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.

Q5.1.	Do you support the Authority's proposal to amend the Code to replace the requirement for an excitation system with a requirement for a voltage control system, to encompass all generating technologies?
Q5.2	Do you see any unintended consequences in making such an amendment?
	Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

7.12. The objective of the proposed Code amendment is to ensure the terminology used in the Code is agnostic to generation technologies.

Evaluation of the costs and benefits of the proposed amendment

7.13. The primary benefit of the proposed Code amendment is to improve the clarity of obligations in the Code, regardless of the technology being used. Further benefits include reducing the administrative burden on the system operator and inverter-based generators in relation to the latter seeking equivalence arrangements.

7.14. We expect the cost of implementing the proposed Code amendment to be minimal on the basis that it largely aligns with the operating practices of generators with inverter-based generating units subject to periodic testing.

Evaluation of alternative means of achieving the objectives of the proposed amendment

7.15. The Authority considered one alternative option to the proposed Code amendment, as summarised in the table below:

Alternative options	Reasons not favoured
Creating a new term to replace the term ‘excitation systems’.	The term ‘voltage control system’ was favoured over other possible terms since it builds on the term ‘control system’ that is already defined in the Code.

Assessment of the proposed Code amendment against section 32(1) of the Act

7.16. The Authority considers that the proposed Code amendment is consistent with the Authority’s main statutory objective, and with section 32(1) of the Act, because it promotes the efficient operation of the electricity industry. It does this by improving clarity of obligations in the Code, regardless of the technology used, and reducing unnecessary administrative burden on the system operator and generators.

Assessment against Code amendment principles

7.17. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority’s Consultation Charter, to the extent they are relevant.

Q5.3. Do you agree the proposed Code amendment is preferable to the other option 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.

Q5.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

8. FSR-006: Amend the Code to apply to all dynamic reactive power compensation devices

The existing arrangements

8.1. The Code requires transmission network owners to undertake periodic tests on each of their static var compensators, which are devices that provide dynamic reactive power compensation. Dynamic reactive power compensation devices help to control (regulate) the voltage at their points of connection to a network, by injecting or absorbing reactive power.

Problem definition

8.2. Currently, the Code requires only static var compensators owned by grid (transmission network) owners to undergo periodic testing. This reflects the technology and ownership arrangements in place when these testing requirements were put in place.

8.3. However, this means these testing requirements do not apply to grid-connected static var compensators owned by someone other than a transmission network owner. It also means these testing requirements do not apply to other grid-connected dynamic reactive power compensation devices (or Flexible Alternating Current Transmission System (FACTS) devices) that are now in use or which could be used in the future. These include, but are not limited to:

(a) static synchronous series compensators

(b) thyristor controlled series devices

(c) static synchronous compensators

(d) thyristor controlled shunt devices.

8.4. The lack of periodic testing requirements for these types of dynamic reactive power compensation devices is inconsistent with the objective of the regime. The Authority considers this objective is to assist asset owners (in this case owners of grid-connected dynamic reactive power compensation devices) to meet their AOPOs by:

(a) verifying the accuracy of data supplied in their asset capability statements, and

(b) verifying to the system operator's satisfaction that these assets are capable of being operated within the limits stated in their asset capability statements.[17]

8.5. Data provided to the system operator via asset capability statements is an essential input to the dynamic models, market models, and planning studies used by the system operator to plan to comply, and to comply, with its PPOs. Therefore, it is important for all types of grid-connected dynamic reactive power compensation devices to undergo periodic testing.

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[17] Electricity Commission, 2008, Amendments to Electricity Governance Rules 2003 – Routine Testing of Assets, p. 3 (paragraph 7).

8.6. Additionally, the exclusion of some grid-connected dynamic reactive power compensation devices from the periodic testing requirements is inconsistent with two key principles guiding the Authority's consideration of options to address issues with the common quality requirements in the Code, particularly in Part 8 of the Code:

(a) promoting competitive neutrality amongst technologies and fuels

(b) signalling the full costs and benefits of alternative technologies and fuels providing the required service or output.[18]

8.7. The Code should be neutral as to which technology can deliver a required service or output (eg, reliability, security of supply, voltage support, frequency keeping) in the most economically and technically efficient manner. The Code should not give a competitive advantage to a grid-connected dynamic reactive power compensation device based on its technology. The Code should also ensure, to the extent practicable, that the full benefits and costs of alternative technologies providing a service or output are signalled, including costs imposed on other parties.

8.8. The omission from periodic testing requirements of some grid-connected dynamic reactive power compensation devices does not signal to any interested or affected party the full benefits and costs of these technology types and confers a regulatory advantage to them.

Proposal

8.9. The Authority proposes amending the Code so that all types of grid-connected dynamic reactive power compensation devices are subject to the Code's periodic testing requirements.

8.10. We propose the following amendments to the Code:

Clause 1.1 – definition of 'reactive capability'

8.11. We propose amending the definition of 'reactive capability' in clause 1.1 of the Code, to include dynamic reactive power compensation devices. We also propose the addition of the word 'reactor' for completeness, which we consider to be a technical and non-controversial amendment:

> **reactive capability** means the **reactive power** injection or absorption capability of **generating units** and other **reactive power** resources such as ~~Static Var Compensators,~~ capacitors, reactors, ~~and~~ synchronous condensers and dynamic reactive power compensation devices, and includes **reactive power** capability of a **generating unit** during the normal course of the **generating unit** operations

Clause 9 (Appendix B, Technical Code A, Schedule 8.3)

8.12. We propose amending clause 9 of Appendix B of Technical Code A, Schedule 8.3 as follows, which includes acknowledging that persons other than a grid owner may

[18] Electricity Authority, 2024, Future Security and Resilience – Review of common quality requirements in the Code: Suite of three consultation papers, pp. 16-17.

own a dynamic reactive power compensation device that is connected to the transmission network:

9 **~~Grid~~ Asset owner ~~static var compensator~~ dynamic reactive power compensation device transient response and control**

Each ~~**grid**~~ **asset owner** with a dynamic reactive power compensation device connected to the **grid** must—

(a) test the transient response, steady state response and a.c. disturbance response of each of its ~~static var compensators~~ dynamic reactive power compensation devices at least once every 10 years; and

(b) test the operation of each of its ~~static var compensators~~ dynamic reactive power compensation devices' analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its ~~static var compensators~~ dynamic reactive power compensation devices' digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph (a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and a.c. disturbance response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including –

(i) a block diagram showing the mathematical representation of the ~~static var compensator~~ dynamic reactive power compensation device; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and

(iii) a detailed functional description of all the components of the ~~static var compensator~~ dynamic reactive power compensation device and how they interact in each mode of control; and

(iv) step response test results; and

(v) a.c. fault recovery disturbance test results; and

(d) based on tests carried out in accordance with paragraphs (b) or (c), provide a set of **control system** test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

Consequential technical and non-controversial change to Schedule 12.5

8.13. In the column 2, row 11 of the table in Schedule 12.5 of the Code, we propose replacing "Static var compensators" with "dynamic reactive power compensation devices".

Q6.1. Do you support the Authority's proposal to amend the Code to require all dynamic reactive power compensation devices to undergo periodic testing?

Q6.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

8.14. The objective of the proposed Code amendment is to ensure that all transmission-connected dynamic reactive power compensation devices, rather than just static var compensators, are included under the Code's requirements.

Evaluation of the costs and benefits of the proposed amendment

8.15. The proposed Code amendment would mean that all transmission-connected dynamic reactive power compensation devices would be subject to periodic testing to ensure they performed in a similar manner to when they were commissioned. The primary benefit of this is that the system operator would have greater assurance that the equipment would perform as expected and any changes would be captured through periodic testing and updated modelling. This better enables the system operator to dispatch the appropriate assets and ancillary services necessary to maintain voltage stability across the transmission system.

8.16. A further benefit is promoting competitive neutrality amongst dynamic reactive power compensation technologies, by better signalling of the benefits and costs of the different technologies.

8.17. The Authority expects the incremental cost of implementing the proposed Code amendment should be relatively minor. We understand the grid owner already undertakes periodic testing of the dynamic reactive power compensation devices that it owns. We also understand the owners of the other grid-connected dynamic reactive power compensation devices test these as part of testing the associated generation assets.

8.18. Therefore, the Authority's view is that the expected benefits of the proposed Code amendment outweigh the costs.

Evaluation of alternative means of achieving the objectives of the proposed amendment

8.19. The Authority considered one alternative option to the proposed Code amendment, as summarised in the table below:

Alternative options	Reasons not favoured
Replace 'static var compensator' with a different term to 'dynamic reactive power compensation device'.	Dynamic reactive power compensation device is the term that will best describe the various dynamic reactive equipment that can be used.

Assessment of the proposed Code amendment against section 32(1) of the Act

8.20. The Authority considers the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes competition in the electricity industry. It does so by removing the existing preferential treatment of transmission-connected dynamic reactive power compensation devices that are not static var compensators. The proposed Code amendment also promotes the reliable supply of electricity to consumers and the efficient operation of the electricity industry by ensuring all transmission-connected dynamic reactive equipment is subject to periodic testing to ensure that it performs as expected.

Assessment against Code amendment principles

8.21. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q6.3. Do you agree the proposed Code amendment is preferable to the other option 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.

Q6.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

9. FSR-007: Treat energy storage systems as only generation for the purposes of Part 8

The existing arrangements

9.1. The Code defines an ‘energy storage system’ (ESS) as all equipment functioning together as a single entity that is able to take electricity from a network, store the energy in another form, and provide injection.[19]

9.2. Battery ESS owners can participate in the wholesale electricity market as generation, dispatchable demand and/or instantaneous reserve.

Problem definition

9.3. There is some ambiguity in the current wording of some of the Code’s common quality-related technical requirements for an ESS. This makes it more difficult for an ESS owner to ensure they are complying with these technical requirements, and for the system operator to monitor ESS owners’ compliance with the technical requirements.

9.4. When discharging, an ESS is generation and so an ESS owner must meet generation-related common quality obligations under Part 8 of the Code. On the other hand, when an ESS is charging, it is acting as a consumer (load) and so the ESS owner must meet load-related common quality obligations under Part 8.

9.5. To complicate matters further, an ESS can change between charging and discharging near-instantaneously, making it difficult to monitor the status of the ESS and the resulting change in obligations in real time. It is also unclear which common quality obligations apply when an ESS is idle (neither charging nor discharging).

9.6. The ambiguity in the Code’s technical requirements for ESSs also makes it difficult for the system operator to derive testing methodologies, determine modelling requirements, and determine connection study requirements and technical assessments for ESSs.

9.7. This ambiguity affects:

(a) voltage support and control

(b) frequency support and control

(c) fault ride through requirements

(d) the provision of automatic under-frequency load shedding (AUFLS)

(e) periodic testing

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19 For completeness, the Authority notes that Schedule 12.4 of the Code (transmission pricing methodology) defines ‘battery storage’ to mean equipment functioning together as a single entity that is able to both—

(a) take electricity and store the energy in another form; and

(b) inject that energy as electricity into the grid, a local network, a non-grid network or consuming plant.

(f) supervisory control and data acquisition (SCADA) indications and measurements

(g) testing at the commissioning stage

(h) modelling requirements.

9.8. The ambiguity also limits the full utilisation of ESS capabilities. For example, the ability of an ESS to switch from charging (load) to discharging (generation) near-instantaneously provides more reserves to the power system, and is therefore more beneficial to the power system, than disconnection under the AUFLS requirements for load. However, this benefit cannot be realised under the existing Part 8 Code provisions.

9.9. The owner of an ESS can apply to the system operator for an equivalence arrangement, or to the Authority for a Code exemption in relation to their AUFLS obligations. However, both of those options impose transaction costs for every application made. Since the issue applies to all potential owners of an ESS, a Code amendment is the preferred option to address the identified problem.

Proposal

9.10. The Authority proposes to amend Part 8 of the Code to treat ESSs above the 30 MW excluded generating station threshold in clause 8.21(1) of the Code as generation for the purposes of Part 8. This proposed amendment would mean an ESS owner or operator would have only the Code obligations of a generator or embedded generator (depending on whether the ESS was connected to the transmission network or a distribution network) regardless of whether the ESS was discharging or charging. For example, under the proposed Code amendment an ESS owner or operator would need to:

(a) ensure their ESS supported frequency when the ESS was charging / discharging

(b) provide asset capability statement information to the system operator for the ESS in regard to the ESS discharging and charging.

9.11. This change would mean that ESSs above the 30 MW excluded generating station threshold would not be subject to the Code's AUFLS obligations. However, they would be required to contribute to supporting frequency during an under-frequency event. Consequently, we also propose the calculations of pre-event demand under clauses 7(6) and 7(6A) of Technical Code B in Schedule 8.3 of the Code exclude the demand of any ESSs that are above the 30MW excluded generating station threshold in clause 8.21(1) of the Code. We have also proposed minor, technical amendments to clause 7(2), to remove the bolding from an undefined term, and to clause 7(6) to properly bolden a defined term.

9.12. Treating ESSs as generation is consistent with what we are typically seeing at present, which is that an ESS is connected to the power system primarily for the purpose of injecting electricity into the power system.

9.13. We propose inserting a new clause 8.1B into the Code and amending clause 8.19, and clause 7 of Technical Code B in Schedule 8.3, as follows.

8.1B Application of this Part to energy storage systems

(1) For the purposes of this Part, the owner or operator of an **energy storage system** with a capacity equal to or above the threshold in clause 8.21(1), in relation to that **energy storage system**, is required to comply only with the obligations under this Part that apply to a **generator** or **embedded generator**, regardless of whether the **energy storage system** is discharging or charging.

(2) For the avoidance of doubt, the thresholds in clauses 8.21(1) and 8.21(2) apply to an **energy storage system** as if the **energy storage system** is a **generator**.

…

8.19 Contributions to frequency support in under-frequency events

…

(5) Each North Island **connected asset owner** and each South Island **grid owner** must ensure that it has established and maintained **automatic under-frequency load shedding** in block sizes and with relay settings in accordance with the **technical codes**.

(6) For the purposes of subclause (5), the owner or operator of a battery **energy storage system** is not considered a **connected asset owner** in relation to that battery **energy storage system**.

…

Schedule 8.3: Technical Code B – Emergencies

…

7 Loading shedding systems

(1) Each North Island **connected asset owner** must ensure, at all times, that an **automatic under-frequency load shedding** system is installed in accordance with subclauses (6) and (6AA).

(2) Every South Island **grid owner** must ensure, at all times, that an **automatic under-frequency load shedding** ~~**system**~~ system is installed in accordance with subclause (6A) for each **grid exit point** in the South Island.

…

(6) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (1) must enable, at all times, automatic **electrical disconnection** of **demand** either**—**

- (a) as 2 blocks of **demand** (each block being a minimum of 16% of the **connected asset owner's** total pre-event **demand** excluding the pre-event **demand** of **energy storage systems** with a capacity equal to or above the threshold in clause 8.21(1))…; or
- (b) in accordance with the **system operator's AUFLS technical requirements report**, as agreed with the **system operator** and subject to subclause (6AA).

(6AA) Each North Island **connected asset owner** must transition as soon as reasonably practicable, and must be proactively engaging with the **system operator** to transition as soon as reasonably practicable, to an **automatic under-frequency load shedding** system that complies with the **system operator's AUFLS technical requirements report**. The transition must be completed before 30 June 2025.

(6AB) Despite subclause (6AA), each North Island **connected asset owner** must exclude the pre-event **demand** of **energy storage systems** with a capacity equal to or above the threshold in clause 8.21(1) in accordance with subclause (6)(a) until such time as the requirement to include this measure in its **automatic under-frequency load shedding** system is included in the **system operator's AUFLS technical requirements report**.

(6AC) For the avoidance of doubt, in relation to subclause (6AB), each North Island **connected asset owner's automatic under-frequency load shedding** system must comply with the **system operator's AUFLS technical requirements report** in all other respects from 30 June 2025.

(6A) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (2) must enable, at all times, automatic **electrical disconnection** of 2 blocks of **demand** (each block being a minimum of 16% of the **grid owner's** total pre-event **demand** excluding the pre-event **demand** of **energy storage systems** with a capacity equal to or above the threshold in clause 8.21(1))…

9.14. The Authority notes we see this proposed Code amendment as an interim measure until we complete a piece of work looking at how the Code most appropriately enables the capability of an ESS when it is acting as generation, a load, or is idle.

Q7.1. Do you support the Authority's proposal to amend the Code to treat ESSs as generation for the purposes of Part 8?

Q7.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

9.15. The objective of the proposed Code amendment is for the Code to enable the capabilities of ESSs to be better realised in relation to supporting common quality on the power system while reducing transaction costs associated with ESS owners seeking equivalence arrangements or exemptions from the obligation to provide AUFLS.

Evaluation of the costs and benefits of the proposed amendment

9.16. The primary benefit of the proposed Code amendment is improved power system management and reliability. ESSs will be able to offer more reserves thereby promoting the reliable supply of electricity and promoting increased competition in the reserves market.

9.17. The Authority expects the proposed Code amendment would have minimal costs. These would relate primarily to changes to connected asset owner systems and processes associated with excluding ESSs with a capacity of 30MW or more from the calculation of the connected asset owner's pre-event demand.

9.18. The Authority considers the exclusion of these larger ESSs from the AUFLS requirements in the Code would impose no cost because these ESSs would still be required to support frequency in accordance with clause 8.19 of the Code.

Evaluation of alternative means of achieving the objectives of the proposed amendment

9.19. The Authority considered three alternative options to the proposal, as summarised in the table below:

Alternative options	Reasons not favoured
The owner of an ESS would need to seek a Code exemption or an equivalence arrangement regarding the ESS's AUFLS obligations.	A Code exemption or an equivalence arrangement both impose transaction costs for every application made. Since the issue applies to all potential owners of an ESS, a Code amendment is the preferred option to address the identified problem.
Amend the AUFLS Technical Requirements (ATR) report to specify that in the case of an AUFLS event, an ESS is required to reduce demand rather than to have a system that automatically electrically disconnects demand.[20]	This may cause confusion because the ATR report will not be consistent with the wording in the Code, resulting in multiple possible interpretations. In addition, this approach would not address all aspects of the issue – only the removal of AUFLS requirements on an ESS.
Comprehensive review of ESS obligations.	The proposed Code amendment is an interim solution to address immediate common quality-related issues associated with ESSs. The Authority intends to conduct a wider common quality-related review of ESSs in addition to this proposal.

Assessment of the proposed Code amendment against section 32(1) of the Act

9.20. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes competition in, the reliable supply by, and the efficient operation of, the electricity industry. It does this by enabling ESS owners to offer more reserves thereby promoting the reliable supply of electricity and increased competition in the

[20] Clause 7(6) of Technical Code B of Schedule 8.3.

reserves market, and by avoiding transaction costs associated with applications by ESS owners for Code exemptions / equivalence arrangements.

Assessment against Code amendment principles

9.21. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q7.3. 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

Q7.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

10. FSR-008: Clarify the definition of generating unit

The existing arrangements

10.1. Clause 1.1 of the Code defines ‘generating unit’ to mean ‘all equipment functioning together as a single entity to produce electricity’.

10.2. This wording dates from early 2020, when the Authority amended the definition to ensure that ‘generating unit’ includes equipment for new generating technologies that use a source of energy other than mechanical force to produce electricity (eg, solar photovoltaic generation).[21]

10.3. The term ‘generating unit’ is used extensively in the Code, including:

(a) as an input to a large number of definitions in Part 1

(b) in various obligations on generators, asset owners and ancillary service agents under Part 8

(c) in certain obligations on Transpower, as a grid (transmission network) owner, under Part 12

(d) in the wholesale electricity market offer arrangements under Part 13

(e) in the wholesale electricity market settlement arrangements under Part 14

(f) in the obligation on generators to provide submission information to the reconciliation manager under Part 15.

Problem definition

10.4. When the Authority amended the definition of ‘generating unit’ in 2020, the intention was for a generating unit to be the smallest entity, including all related equipment essential to its functioning as a single entity, that can produce electricity independently of other entities that are part of the same system.

10.5. In its current form, the definition of generating unit can be interpreted more broadly or more narrowly than intended. This is causing uncertainty about Code obligations on both asset owners and the system operator. The Authority is concerned the current definition of generating unit may lead to misinterpretation and inconsistent application of the Code’s common quality requirements. This is particularly the case in relation to wind farms, solar photovoltaic farms and battery farms.

Proposal

Clause 1.1 – definition of ‘generating unit’

10.6. The Authority proposes the term ‘generating unit’ be defined in terms of its frequency and voltage control systems. This clarification would address the problem described above by ensuring that a generating unit is understood as the smallest entity that is able to produce electricity independently of other entities that are part of the same system.

[21] Previously generating unit was defined as a machine that generates electricity.

10.7. The proposed amendment is:

generating unit means the smallest set of ~~all~~ equipment functioning together as a single entity to produce **electricity** and that has its own frequency and/or voltage **control systems**

Q8.1. Do you support the Authority's proposal to amend the definition of generating unit in clause 1.1 of the Code so that it refers to a generating unit having a frequency and/or voltage control system?

Q8.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

10.8. The objective of the proposed Code amendment is to make it easier for generators and the system operator to understand, and to comply with, their Code obligations.

Evaluation of the costs and benefits of the proposed amendment

10.9. The primary benefit is increased regulatory clarity, reducing the potential for misinterpretation and supporting the consistent application of requirements.

10.10. The cost of implementing this amendment is expected to be minimal.

Evaluation of alternative means of achieving the objectives of the proposed amendment

10.11. The Authority considered one alternative option to the proposal, as summarised in the table below:

Alternative options	Reasons not favoured
Specifically clarify what the 'generating unit' refers to for each type of generation.	Increased complexity and likely to be affected by new and evolving technologies.

Assessment of the proposed Code amendment against section 32(1) of the Act

10.12. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the efficient operation of the electricity industry by improving regulatory clarity and consistency.

Assessment against Code amendment principles

10.13. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q8.3. Do you agree the proposed Code amendment is preferable to the other option 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.

Q8.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

11. FSR-009: Clarify the Code's fault ride through requirements

The existing arrangements

11.1. The fault ride through (FRT) requirements, specified in clause 8.25A of the Code, define how long and under what conditions generators subject to the FRT requirements[22] must remain connected during faults. These requirements were introduced in 2016 to address the growing share of generation from inverter-based resources (IBRs) and are designed to ensure that applicable generators remain connected and support the grid (transmission network) during short-term faults or disturbances. IBRs are more sensitive to faults and may disconnect to avoid damage, which can worsen grid stability and negatively impact non-IBR generating units / stations.

Problem definition

11.2. The Code's FRT requirements apply across all types of generating technologies. While the FRT requirements are effective for managing IBR-based generating units, these requirements have posed significant challenges for some machine-based synchronous generating units.

11.3. These synchronous generating units are typically larger, rotating machines that rely on mechanical processes to generate electricity. When a fault or disturbance occurs on a network, these generating units can experience significant physical stress. Some machine-based synchronous generating units are unable to fully comply with the FRT requirements in the Code, due to their inherent characteristics. As a result, the owners of these generating units have had to apply to the system operator for a dispensation from the FRT requirements.

11.4. The Authority is aware that some overseas jurisdictions have developed separate FRT curves for machine-based synchronous generation and IBR-based generation. The Authority intends to review the current FRT requirements in the Code, and may consider adopting a similar approach to overseas jurisdictions (or another suitable solution). However, this is expected to be a longer-term project. In the meantime, we consider there is a benefit to be realised from a short-term solution that reduces transaction costs associated with dispensations.

Proposal

11.5. The Authority proposes to amend clause 8.25A of the Code to allow a machine-based synchronous generating unit to be treated as compliant with the FRT requirements if:

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22 Being the following generation assets of a generator (see clause 8.25D of the Code):

(a) any asset at a generating station that exports 30MW or more to the transmission network or to a local distribution network

(b) a wind generating station when it operates at less than 5 percent of rated MW.

(a) the generator can demonstrate that full compliance is not possible due to the generating unit's inherent stability characteristics, and

(b) the generating unit complies with the requirements in subclauses (1) and (2) of clause 8.25A to the extent reasonably possible taking into account the generating unit's inherent stability characteristics; and

(c) the generator has taken all reasonable measures to support grid stability taking into account the generating unit's inherent stability characteristics.

11.6. We propose the following amendment to clause 8.25A of the Code:

8.25A Fault ride through

(1) Each **generator** must ensure that each of its **assets**, when **electrically connected** to a **network**, is capable of remaining stable and **electrically connected** when the **grid**'s lowest **line**-to-**line** voltage is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.1 (for an **asset** in the North Island) or Figure 8.2 (for an **asset** in the South Island) for the period of 6 seconds immediately following the commencement of a zero impedance three-phase short circuit fault, or an unbalanced short circuit fault, on any part of the **grid** at 110 kV or 220 kV in the **island** in which the **asset** is connected.

(2) Each **generator** must ensure that each of its **assets**, when **electrically connected** to a **network**, is capable of remaining stable and **electrically connected** when the highest **line**-to-**line** voltage at Haywards 220 kV bus (for an **asset** in the North Island) or Benmore 220 kV bus (for an **asset** in the South Island) is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.3 for the period of 1 second immediately following the commencement of a trip of the **HVDC link**.

(3) Whether a **generator** is complying with subclause (2) must be determined using power system analysis that uses—

(a) study cases provided by the relevant **grid owner**; and

(b) relevant system assumptions provided by the **system operator**.

(4) A **generator** is not required to comply with subclause (1) in respect of an **asset** in the event of a fault of a type described in subclause (1) if the **asset** becomes isolated from the **grid** as a result of the fault.

(5) A **generating unit** need not comply with subclause (1) to the extent that it is complying with a **special protection scheme** approved by the **system operator**.

(6) The absolute **grid** voltage (per unit) shown on the Y axis of Figure 8.1 and Figure 8.2 is the ratio of **grid** lowest **line**-to-**line** voltage on a **line** to the nominal operating voltage of the **line** (that is, 110 kV or 220 kV).

(7) A **generator** operating a machine-based **synchronous generating unit** complies with subclauses (1) and (2) if the **generator** can demonstrate to the **system operator's** satisfaction, acting reasonably, that:

(a) it is not possible for the **generator** to comply fully with those subclauses due to the **generating unit's** inherent stability characteristics;

(b) despite paragraph (a), the **generator** meets the requirements in those subclauses to the extent reasonably possible taking into account the **generating unit's** inherent stability characteristics; and

(c) the **generator** has taken all reasonable measures to support the stability of the **grid** taking into account the **generating unit's** inherent stability characteristics.

Q9.1. Do you support the Authority's proposal to amend the Code to allow a machine-based synchronous generating unit to be deemed compliant with the Code's FRT requirements if full compliance is not possible due to the generating unit's inherent stability characteristics and the generator has taken all reasonable measures to support grid stability taking into account the generating unit's inherent stability characteristics?

Q9.2. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

Regulatory statement

Objectives of the proposed amendment

11.7. The objective of the proposed Code amendment is to reduce transaction costs associated with generators seeking a dispensation from the FRT requirements for a machine-based synchronous generating unit that is unable to fully comply with the Code's FRT requirements due to the generating unit's inherent stability characteristics.

Evaluation of the cost and benefit of the proposed amendment

11.8. The primary benefit of the proposed Code amendment is a reduction in the transaction costs incurred by generators and the system operator as a result of generators seeking a dispensation from the FRT requirements because of the inherent stability characteristics of their machine-based synchronous generating units. This reduction in transaction costs is expected to result from fewer applications for dispensations.

11.9. The incremental cost of the proposed Code amendment is expected to be minimal, since generators already study and advise the system operator of any issues they face complying with the Code's FRT requirements because of the inherent stability characteristics of their generating units.

Evaluation of alternative means of achieving the objectives of the proposed amendment

11.10. The Authority considered one alternative option to the proposed Code amendment, as summarised in the table below:

Alternative options	Reasons not favoured
Develop separate FRT curves for machine-based synchronous generating units and for IBR-based generating units.	The Authority intends to investigate this option via a longer-term project. The proposed amendment is intended to be a shorter-term solution.

Assessment of the proposed Code amendment against section 32(1) of the Act

11.11. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the efficient operation of the electricity industry by reducing transaction costs.

Assessment against Code amendment principles

11.12. The proposed Code amendment is consistent with the Code amendment principles, outlined in the Authority's Consultation Charter, to the extent they are relevant.

Q9.3. Do you agree the proposed Code amendment is preferable to the other option 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

Q9.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

Appendix A Format for submissions

Submitter	

FSR-001: Remove the exclusion for wind-powered generation from periodic testing requirements

Questions	Comments
Q1.1. Do you support the Authority's proposal to apply the periodic testing requirements in Appendix B of Technical Code A of Schedule 8.3 to wind generation? If you disagree, please give reasons and provide alternatives that address the identified problem with wind generation being excluded from the periodic testing requirements.	
Q1.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q1.3. Do you agree the proposed Code amendment is preferable to the other option 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.	
Q1.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-002: Clarify that embedded generators must provide an asset capability statement in a format specified by the system operator

Questions	Comments
Q2.1. Do you support the Authority's proposal to amend the Code to clarify that: (a) embedded generators must provide asset capability statement information to the system operator in the form from time to time published by the system operator, and (b) the requirement to provide an asset capability statement to the system operator applies only to generators with a generating unit with rated net maximum capacity equal to or greater than 1MW?	
Q2.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q2.3. Do you agree with the proposed Code amendment? 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	
Q2.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-003: Include distributors and energy storage systems as potential causers of under-frequency events

Questions	Comments
Q3.1. Do you support the Authority's proposal to amend the definition of 'causer' in clause 1.1 of the Code so that it refers to the action that results in a UFE, including an increase in electricity demand (load), and the consequential amendments to clauses 8.60 to 8.66, including proposed new clause 8.64A?	
Q3.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q3.3. 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.	
Q3.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-004: Amend the requirement to have a speed governor

Questions	Comments
Q4.1. Do you support the Authority's proposal to amend clause 1.1 of the Code, and clauses 3, 4 and 5 of Appendix B of Technical Code A of Schedule 8.3, to broaden them to apply to inverter-based generation technologies?	

Q4.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q4.3. Do you agree the proposed Code amendment is preferable to the other option 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.	
Q4.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-005: Amend the requirement to have an excitation system

Questions	Comments
Q5.1. Do you support the Authority's proposal to amend the Code to replace the requirement for an excitation system with a requirement for a voltage control system, to encompass all generating technologies? Please explain your answers.	
Q5.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q5.3. Do you agree the proposed Code amendment is preferable to the other option 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.	

Q5.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-006: Amend the Code to apply to all dynamic reactive power compensation devices

Questions	Comments
Q6.1. Do you support the Authority's proposal to amend the Code to require all dynamic reactive power compensation devices to undergo periodic testing?	
Q6.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q6.3. Do you agree the proposed Code amendment is preferable to the other option 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.	
Q6.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-007: Treat energy storage systems as only generation for the purposes of Part 8

Questions	Comments
Q7.1. Do you support the Authority's proposal to amend the Code to treat ESSs as generation for the purposes of Part 8?	

Q7.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q7.3. 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	
Q7.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-008: Clarify the definition of generating unit

Questions	Comments
Q8.1. Do you support the Authority’s proposal to amend the definition of generating unit in clause 1.1 of the Code so that it refers to a generating unit having a frequency and/or voltage control system?	
Q8.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q8.3. Do you agree the proposed Code amendment is preferable to the other option 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.	

Q8.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

FSR-009: Clarify the Code's fault ride through requirements

Questions	Comments
Q9.1. Do you support the Authority's proposal to amend the Code to allow a machine-based synchronous generating unit to be deemed compliant with the Code's FRT requirements if full compliance is not possible due to the generating unit's inherent stability characteristics and the generator has taken all reasonable measures to support grid stability taking into account the generating unit's inherent stability characteristics?	
Q9.2. Do you see any unintended consequences in making such an amendment? Please explain your answers.	
Q9.3. Do you agree the proposed Code amendment is preferable to the other option 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	
Q9.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	