Future Security and Resilience - Review of common quality requirements in Part 8 of the Code

Issues Paper

Submissions close: 5pm Tuesday 30 May 2023

4 April 2023

Executive summary

The purpose of this paper is to consult with interested parties on some issues that have been identified with the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). These issues are occurring, or are expected to occur, because of:

(a) the uptake of inverter-based variable and intermittent resources, and/or

(b) how the Code enables different technologies.

This issues paper is the start of Phase 3 of the FSR work programme

This issues paper represents the start of Phase 3 of the Authority's Future Security and Resilience (FSR) work programme. The FSR programme is a multi-year work programme to make sure New Zealand's power system remains secure and resilient as the country transitions towards a low-emissions energy system.

Phase 3 of the FSR work programme is about understanding and addressing the security and resilience challenges and opportunities identified and prioritised during Phases 1 and 2 of the FSR programme, with a focus on the whole of New Zealand's power system.[1]

The highest priority activity in Phase 3 of the FSR work programme is reviewing the common quality requirements in Part 8 of the Code, to ensure they enable evolving technologies, particularly inverter-based resources, in a manner that promotes the Authority's statutory objectives.

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, or is likely to have, linkages with other parts of the Code. The Authority will carefully consider these linkages as part of the review of the common quality requirements in Part 8.

A first-principles approach to reviewing common quality requirements

The Authority is adopting a first-principles approach to reviewing the extent to which the Code's common quality requirements appropriately enable technologies. This is to ensure, as far as practicable, that underlying issues are identified.

Taking a first-principles approach to identifying common quality issues should result in a more complete and coherent set of common quality Code requirements that enable technologies in a manner that promotes the Authority's statutory objectives.

However, please note that the Authority is not undertaking a first principles review of Part 8 of the Code in its entirety. Part 8 requirements that do not relate to common quality are outside the scope of this work.

Some important common quality issues have been identified

The Authority has engaged with the system operator and a number of other stakeholders over:

(a) the implications for the common quality requirements in the Code from the uptake of increasing amounts of inverter-based resources

[1] Further information on Phase 1 and Phase 2 is available at https://www.ea.govt.nz/development/work-programme/risk-management/future-security-and-resilience-project/.

(b) the extent to which the Code's common quality requirements enable technologies, particularly inverter-based resources, in a manner that promotes the Authority's statutory objectives.

Through this engagement the following common quality issues have been identified:

(1) inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia

(2) inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows

(3) inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system

(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 30 MW to a network

(5) there is some ambiguity around the applicability of harmonics standards

(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

(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.

Your feedback is welcomed

The Authority welcomes feedback from interested parties on:

(a) the description of each identified issue and whether you consider it is a high priority to address

(b) any other high priority common quality issues not identified in this paper that are occurring or that you expect to occur because of:

    (i) the uptake of inverter-based resources, and/or

    (ii) how the Code enables different technologies.

The Authority acknowledges the content of this paper is technical, that a number of industry stakeholders have important competing priorities at present, and that Easter and school holidays are upon us. Therefore, the Authority has allowed an 8-week consultation period. However, if any submitters face difficulties responding in this timeframe, please do not hesitate to get in touch with the Authority.

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1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to consult with interested parties on several issues related to the *common quality* requirements in Part 8 of the Code that are occurring or that are expected to occur because of:

(a) the uptake of inverter-based variable and intermittent resources, and/or

(b) how the Code enables different technologies.

1.2 For the purposes of this paper, the term *common quality* refers to those elements of the quality of electricity transported across networks that cannot be technically or commercially isolated to an identifiable person or group of persons.

1.3 The issues described in this paper have been identified as part of the Authority's Future Security and Resilience (FSR) work programme. An overview of this programme is provided in the next section.

How to make a submission

1.4 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to fsr@ea.govt.nz with "Issues Paper—Review of common quality requirements in Part 8 of the Code" in the subject line.

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

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

(a) indicate which part should not be published,

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

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

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

1.8 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

1.9 Please deliver your submission by **5pm** on Tuesday, **30 May 2023**.

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

2 The Future Security and Resilience work programme

What is the FSR programme?

2.1 The Authority's FSR programme is a multi-year work programme that has as its purpose ensuring New Zealand's power system remains secure and resilient as the country transitions towards a low-emissions energy system. By "power system" we mean all components of the New Zealand electricity system that underpin the New Zealand electricity market, including generation, transmission, distribution, and load assets.

"Security", "Resilience" and "Reliability"

"Security" refers to the ability of the power system to withstand adverse events, ensuring a steady and stable network that delivers generation to where it is needed (ie, significant adverse events do not cause electricity outages).

"Resilience" refers to the ability to identify and mitigate high-impact low-frequency threats to the power system quickly and efficiently, to minimise damage to infrastructure and support services, while enabling a quick recovery and restoration of the power system to a stable operating state.

"Reliability" refers to both the continuity of electricity supply (ie, the rate and duration of electricity outages, including because of insufficient fuel for electricity generation), and the quality of electricity supply (eg, the frequency and voltage of electricity).[2]

2.2 Lowering emissions from New Zealand's energy use will require increasing electrification of sectors of the economy (eg, transport and industrial processes), and meeting the increased electricity demand with renewable electricity generation. A critical challenge is to make this transition while delivering a level of reliability of electricity supply that reflects consumers' preferences and minimises total costs,[3] as the power system becomes increasingly complex.

2.3 Enabled by evolving technologies, the transition to a low-emissions power system is expected to bring about increasingly distributed sources of electricity generation and storage, in many cases located closer to consumers. It is also expected to bring about greater demand-side flexibility.

2.4 Coordinating the operation of New Zealand's power system and electricity market arrangements will need to evolve to accommodate and facilitate the changes occurring in the electricity sector. In particular, coordinating the real-time operation of New

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2 See the following:

- *Interpretation of the Authority's statutory objective*, 14 February 2011, available at https://www.ea.govt.nz/assets/dms-assets/31/Interpretation-of-the-Authoritys-statutory-objective-with-Explanatory-Note.pdf
- Section 5 of the FSR Phase 1 report prepared for the Authority by the system operator, available at https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Phase-1-final-report.pdf.

3 See *Interpretation of the Authority's statutory objective*, 14 February 2011.

Zealand's power system is expected to become more difficult as the percentage of variable and intermittent generation and load resources increases. As the Market Development Advisory Group (MDAG) has noted, this is because:

(a) many of New Zealand's new electricity supply sources will not be readily controllable, because they are governed by weather conditions

(b) the New Zealand power system will move increasingly from being balanced in real time using a relatively small number of large resources to being balanced in real time using more 'many and small' resources (eg, smaller scale generation including battery energy storage systems (BESS's), and demand-side flexibility).[4]

2.5 The FSR programme is focussed on how the power system operates in real time, or close to real time, to balance electricity supply and demand continuously and to supply consumers with electricity that is of an appropriate quality. The FSR programme is not assessing the power system's ability to ensure electricity supply is able to meet electricity demand over periods longer than a few days (often referred to as "energy adequacy"). Other programmes of work are considering this, such as:

(a) the '*NZ Battery Project*', which is being undertaken by the Ministry of Business, Innovation and Employment (MBIE). This project will provide comprehensive advice on the technical, environmental and commercial feasibility of pumped hydro and other potential energy storage projects to supply electricity when New Zealand's hydro lakes are low for extended periods.[5]

(b) the '*Price discovery under 100% renewable electricity supply*' project, which is being undertaken by MDAG. This project is focussed on the necessary changes to the wholesale electricity market in a world of 100% renewable supply, to ensure there are economically efficient price signals (from short term to long term) to promote the Authority's statutory objectives.[6] [7]

(c) the Authority's consideration of options to better manage potential tight supply situations for winter 2023 and beyond.[8]

2.6 The Authority is also undertaking other work programmes designed to support New Zealand's transition to a low-emissions energy system. These include:

(a) the 'Updating regulatory settings for (electricity) distribution networks' project[9]

(b) the 'Wholesale (electricity) market competition review'[10]

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4 Market Development Advisory Group, February 2022, Price Discovery Under 100% Renewable Electricity Supply – Issues Discussion Paper, p.19.

5 See https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/.

6 See https://www.ea.govt.nz/development/advisory-technical-groups/mdag/mdag-price-discovery-project/.

7 The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The additional objective applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers.

8 See https://www.ea.govt.nz/development/work-programme/risk-management/winter-2023/development/.

9 See https://www.ea.govt.nz/development/work-programme/evolving-tech-business/updating-regulatory-settings-for-distribution-networks/.

10 See https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2021/wholesale-market-competition-review-2/.

(c) the 'Participation of new generating technologies in the wholesale market' project.[11]

This issues paper is the start of Phase 3 of the FSR programme

2.7 This issues paper represents the start of Phase 3 of the FSR programme. This phase is about understanding and addressing the security and resilience challenges and opportunities identified and prioritised during Phases 1 and 2 of the FSR programme.

Phase 1 – Identifying FSR challenges and opportunities

2.8 The Authority commenced the FSR programme in 2021. Under Phase 1 of the FSR programme, the Authority commissioned a report by the system operator on challenges and opportunities for the security and resilience of New Zealand's power system as it transitions towards a low-emissions energy system.

2.9 A draft of the Phase 1 report provided a starting point for the Authority to engage with industry stakeholders.

2.10 Following consultation with interested parties, the Phase 1 report was finalised and published in March 2022.[12] This ended Phase 1 of the FSR programme.

Phase 2 – Prioritising FSR activities

2.11 Phase 2 of the FSR programme identified a roadmap of activities over a 10-year period that were designed to enable an understanding of the challenges and opportunities identified in Phase 1 and to address them. The roadmap:

(a) prioritised activities for delivery over the 10-year period

(b) outlined an approach to support or adjust the prioritisation of activities over time, using a set of indicators to monitor trends and industry observations.

2.12 The Authority consulted with interested parties on the draft roadmap in the first half of 2022. As part of this consultation, the Authority and system operator held stakeholder workshops on the FSR programme and the draft roadmap.

2.13 Following consultation with interested parties, the FSR roadmap was finalised and published in August 2022.[13] This ended Phase 2 of the FSR programme.

Phase 3 – Undertaking FSR activities, starting with reviewing Part 8 common quality requirements

2.14 The highest priority activity on the FSR roadmap is a review of the common quality requirements in Part 8 of the Code, to ensure they enable evolving technologies, particularly inverter-based resources, in a manner that promotes the Authority's statutory objectives.

2.15 This issues paper is the start of the review of these common quality requirements.

2.16 For the purposes of this issues paper, common quality is defined to apply across all of New Zealand's connected transmission and distribution networks, rather than across only the transmission network.

11 See https://www.ea.govt.nz/development/work-programme/evolving-tech-business/participation-of-new-generating-technologies-in-the-wholesale-market/.

12 See https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Phase-1-final-report.pdf.

13 See https://www.ea.govt.nz/assets/dms-assets/30/Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf.

What is "common quality"?

Part 8 of the Code is about "common quality". The Code defines common quality to mean:

> *Those elements of quality of electricity conveyed across the grid that cannot be technically or commercially isolated to an identifiable person or group of persons.*

2.17 As the Authority has stated publicly, Phase 3 of the FSR programme will look at the whole power system in New Zealand, thereby broadening the initial focus, which was on the transmission network.[14] By "transmission network", we mean the system of transmission lines, substations and other works, including the HVDC link, used to connect grid injection points and grid exit points to convey electricity throughout the North Island and the South Island of New Zealand.[15]

2.18 The initial focus complemented the Authority's '*Updating the regulatory settings for electricity distribution networks*' project. Consistent with stakeholder feedback on the draft FSR roadmap, the Authority considers it appropriate for Phase 3 of the FSR programme to include in its scope security and resilience challenges and opportunities that span all of New Zealand's interconnected transmission and distribution networks. This acknowledges that various security and resilience challenges and opportunities will be common to the transmission network and distribution networks.

2.19 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, or is likely to have, linkages with other parts of the Code. The Authority will carefully consider these linkages as part of the review of the common quality requirements in Part 8.

The Authority's proposed review of Part 6 of the Code

2.20 Part 6 of the Code regulates distributed generation, which is generation connected directly to a distribution network or indirectly via a consumer installation. The Authority believes Part 6 of the Code should be reviewed and updated. Currently, the Authority is considering feedback from interested parties[16] on the inclusion of the following issues in a review:

(a) amend Part 6 to explicitly include all forms of distributed energy resource

(b) amend the processes set out in Part 6 for the connection of distributed generation to distribution networks, to:

(i) increase the size threshold for distributed generation applying for connection under the Part 1 application process

(ii) adjust the timeframe for processing distributed generation applications under the Part 1A (streamlined) process

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14 See p. 6 of the Authority's covering paper for the final FSR roadmap, available at: https://www.ea.govt.nz/assets/dms-assets/30/Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf.

15 The Code uses the term "grid" to mean New Zealand's transmission network.

16 Received in submissions on the Authority's December 2022 consultation paper "Issues paper: Updating the Regulatory Settings for Distribution Networks", available at https://www.ea.govt.nz/assets/dms-assets/31/Issues-paper_-Updating-the-regulatory-settings-for-distribution-networks.pdf.

(iii) add a new process for large-scale distributed generation applying for connection to a distribution network

(iv) review the Code provision relating to the prioritisation of distributed generation connection applications

(c) strengthen power quality standards for distribution networks

(d) review the maximum fees for the connection of distributed generation that are prescribed in Part 6.

2.21 The inclusion of power quality standards in the proposed review of Part 6 is consistent with the Authority's intention to take a whole-of-power-system approach to the review of common quality.

The Authority is taking a first-principles approach

2.22 The Authority is adopting a first-principles approach to reviewing the extent to which the Code's common quality requirements appropriately enable technologies. That is, the Authority is looking at the fundamental reasons for placing common quality Code obligations on existing and evolving technologies. This is to ensure as far as practicable that underlying issues are identified, rather than symptoms or exacerbators of issues.

2.23 Taking a first-principles approach to identifying common quality issues should result in a more complete and coherent set of common quality Code requirements that enable technologies in a manner that promotes the Authority's statutory objectives.

2.24 The Authority notes it is *not undertaking* a first principles review of Part 8 of the Code *in its entirety* as part of the FSR programme. Part 8 requirements that do not relate to common quality are outside the scope of this work.

The Authority will review the common quality requirements in stages

2.25 The Authority intends to review the common quality requirements in Part 8 of the Code in stages, as follows:

(a) *an issues paper (this paper)*
setting out common quality issues identified as being of a high priority to address, with the opportunity for stakeholder feedback to contribute to the Authority's understanding of the issues and to identify any other issues for consideration

(b) *an options paper (anticipated to be in the first half of 2024)*
outlining options the Authority is considering in order to address the high priority issues relating to common quality requirements, with the opportunity for stakeholder input to the Authority's assessment of the options

(c) *a decisions paper (anticipated to be in late 2024 / early 2025)*
sharing the Authority's decisions and rationale for any proposals to amend (or to not amend) common quality requirements in Part 8 of the Code that were identified in the issues and options papers. If any amendments are proposed, the Authority will take these through the standard process for amending the Code.

The Authority may establish a technical working group

2.26 The Authority is considering establishing a technical working group to support the Authority's consideration of the common quality requirements in the Code.

2.27 If such a group were to be established, the Authority envisages having the group in place to support the Authority's consideration of options to address the issues identified during the consultation on this paper.

Several common quality issues have been identified

2.28 The Authority has engaged with the system operator and a number of other stakeholders over:

(a) the implications for the common quality requirements in the Code from the uptake of increasing amounts of inverter-based resources

(b) the extent to which the Code's common quality requirements appropriately[17] enable technologies, particularly inverter-based resources.

> **"Inverters" and "Inverter-based resources"**
>
> An "inverter" is an electronic device that converts direct current (DC) electricity to alternating current (AC) electricity. (Electronic devices that convert AC electricity to DC electricity are known as "rectifiers".)
>
> An "inverter-based resource" is equipment that uses an inverter when functioning. Examples include wind generation, solar photovoltaic (PV) generation, and a BESS.

2.29 Stakeholders the Authority has engaged with include distributors, generators, retailers, industry representative bodies, and Transpower as a transmission network owner.

2.30 Through this stakeholder engagement the following common quality issues have been identified:

(a) inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia

(b) inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows

(c) inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system

(d) 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 30 MW to a network

(e) there is some ambiguity around the applicability of harmonics standards

(f) 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

[17] Ie, in a manner that promotes the Authority's statutory objectives.

(g) 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.

2.31 These issues are described in the remaining sections of this paper. The Authority considers addressing each of these issues should be a high priority.

2.32 The Authority welcomes feedback from interested parties on:

(a) the description of each identified issue and whether you consider it is a high priority to address

(b) any other high priority common quality issues not identified in this paper that are occurring or that you expect to occur because of:

(i) the uptake of inverter-based resources, and/or

(ii) how the Code enables different technologies.

“Active power” and “Reactive power”

The Code defines active power to mean the product of voltage, current and the cosine of the phase angle between them, normally measured in kilowatts (kW). In layman’s terms, active power is the electrical energy delivered to a consumer that is then converted from electrical energy to some other form of energy (eg, heat, light, to move or lift objects).

The Code defines reactive power to mean the product of voltage, current and the sine of the phase angle between them, normally measured in kiloVolt-Amps reactive (kVAr). In layman’s terms, reactive power is the electrical energy used to support the delivery of active power to a consumer.

Key assumptions underpinning the description of the issues

2.33 The Authority notes that assumptions underpin the description of each of the above issues in this paper. Key assumptions include:

(a) inverter-based resources will be the dominant form of newly installed generation technology going forward

(b) distributed energy resources (DERs) will increase exponentially in number and capacity over the next 5–10 years

(c) within 5 years the number and capacity of generators less than 30 MW will be larger than currently (by approximately 10%)

(d) within 5 years the capacity of generators connected to distribution networks will have increased by approximately 25% over the current level.[18]

18 The last two assumptions are based on data held by Transpower.

3 Issue 1: Inverter-based resources cause more frequency fluctuations

3.1 This section describes the issue of inverter-based variable and intermittent resources causing more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia.

A description of the status quo

Key regulatory requirements for the frequency of electrical current

3.2 New Zealand has adopted a nominal frequency of 50 Hertz (Hz) for alternating electrical current. This is consistent with most countries internationally.

3.3 The Code requires the system operator to maintain frequency within 0.4% of 50 Hz (ie, 49.8 – 50.2 Hz, 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 45 Hz in the South Island and 47 Hz in the North Island, and must return frequency to at least 49.25 Hz within 60 seconds. The Code does not specify equivalent upper bounds on frequency fluctuations.

3.4 These Code requirements are consistent with, albeit more stringent than, the Electricity (Safety) Regulations 2010, which require the frequency of electricity supplied to be maintained within 1.5% of 50 Hz (ie, 49.25 – 50.75 Hz), except for momentary fluctuations. The Electricity (Safety) Regulations permit this requirement to be varied for electricity supplied at other than standard low voltage,[19] if the electricity supplier and the person receiving the electricity supply agree.[20]

Why it is necessary to maintain frequency within the normal band

3.5 There are two primary reasons why frequency must be maintained within the ranges specified in the Code:

(a) to avoid equipment that produces or uses electricity being damaged and causing economic loss, and potentially physical harm

(b) to avoid cascade failure of the power system, caused by equipment disconnecting from the power system in order to avoid damage, which again results in economic loss and potentially physical harm.

3.6 A further, but lesser, reason for maintaining frequency within the ranges specified in the Code is to manage frequency time error. Frequency time error is the time difference between actual time and a synchronous clock running on mains supply. Some timekeeping devices (eg, clock radios) use electrical current frequency as a time signal, meaning that if frequency is under or over 50 Hz, these devices show incorrect time. The Code requires the system operator to maintain frequency time error to be no more than five seconds and to be zero at least once each day.[21]

19 230 volts AC to 460 volts AC.

20 See regulation 29 of the Electricity (Safety) Regulations 2010.

21 See clause 7.2C of the Code.

Three mechanisms are used to maintain frequency within the normal band

3.7 Short-term electricity demand and supply imbalances occur continuously, and often unpredictably, which affects the frequency of the power system. Under normal circumstances, the system operator relies on a combination of the following Code-mandated mechanisms to manage these imbalances and maintain normal frequency quality:

(a) generator dispatch

(b) frequency keeping

(c) generator asset owner performance obligations (AOPOs) – particularly free governor action.

Mechanism 1: The maintenance of frequency using generator dispatch

3.8 At regular intervals, usually five minutes, the system operator determines generator dispatch trajectories to meet expected generation requirements to balance electricity supply and demand across the transmission network during the next five-minute interval. In doing so, the system operator uses generators' offers into the wholesale electricity market, so that least-cost, security-constrained generation dispatch is achieved in the market. Biasing the generation dispatch above or below the expected electricity demand for the next five minutes helps to correct frequency deviations or system time error.

Mechanism 2: The maintenance of frequency using frequency keeping providers

3.9 Frequency keeping providers (frequency keepers) are generating stations that respond to changes in system frequency by adjusting their output to return frequency to 50 Hz. Frequency keeping is a common feature of electricity markets around the world.

3.10 Since 2013 (in the North Island) and 2014 (in the South Island), multiple generating stations have been able to provide frequency keeping within the same 30-minute trading period. This service is referred to as "multiple provider frequency keeping" (MFK).[22]

3.11 Generating stations selected to provide the MFK service in a trading period increase or decrease their output in response to a central control signal sent by the system operator. Such changes in output are coordinated via the system operator's MFK control, to correct frequency deviations or system time error.[23] The system operator selects MFK providers, by island, in accordance with MFK market offers. Currently, the system operator procures 15 MW of MFK in each island.[24]

3.12 In January 2015, the system operator brought into full operational use the high voltage direct current (HVDC) link's frequency keeping modulation control (FKC). FKC varies the active power on the HVDC link to tie together the North Island and South Island frequencies. This followed trials in late 2014. FKC has allowed MFK and instantaneous

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22 Internationally, frequency keeping is often called "frequency regulation service", with providers coordinated via automatic generation control (AGC), which is similar to the MFK function in New Zealand. AGC is also used for dispatch purposes in some electricity markets.

23 Prior to 1 July 2013 for the North Island and 4 August 2014 for the South Island, station-based control systems were used to manage frequency in the normal band.

24 Prior to May 2016 the system operator procured 75 MW of frequency keeping—25 MW in the South Island and 50 MW in the North Island. These MW quantities represent the MW band within which frequency keepers ramp their MW set points up and down (ie, previously +/- 50 MW in the North Island and +/- 25 MW in the South Island; now +/- 15 MW in the North Island and +/- 15 MW in the South Island).

reserves to be shared between the North Island and South Island. The use of FKC has changed frequency management in the following ways:

(a) The system operator has been able to reduce the quantity of MFK it procures nationally from 75 MW to 30 MW without causing any material deterioration in the quality of system frequency.

(b) More of the work of managing frequency has shifted from contracted MFK providers to inherent generator governor response. This is because the speed of response of FKC and generator governors is faster than the speed of the MFK controls.[25]

3.13 The system operator also procures back-up single provider frequency keeping (back-up SFK) services in each island. This is in case the MFK system is unavailable.[26] A single back-up SFK provider is used rather than two (island-based) back-up SFK providers during any period when MFK is not operating but FKC is. Otherwise, the island-based back-up SFK providers would "fight" each other to maintain frequency across both islands. Island-based back-up SFK providers are used if there is a loss of both MFK and FKC.

Mechanism 3: The maintenance of frequency using generator AOPOs

3.14 Part 8 of the Code contains AOPOs that specify the contributions generators must make to maintaining frequency in the normal band. Clause 8.17 of the Code sets out the overarching requirement on generators to:

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

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

(a) ensure their governor systems automatically respond to changes in system frequency

(b) agree governor settings with the system operator.[27]

3.16 Governors are standard features of conventional synchronous generating technologies powered by hydro, steam and gas turbines. The collective response of generators operating under governor control is an essential part of normal frequency management. It acts in the first instance to limit system frequency changes due to imbalances between generation and demand.

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25 Some shift in frequency management duty towards generator governors occurred with the implementation of MFK in mid-2013, due to MFK being a slower form of control than the station-based frequency control that pre-dated MFK.

26 Providers tender a constant fee for availability, with the system operator able to call on them if MFK systems are unavailable. Providers that are called upon by the system operator receive their offered price.

27 Clause 5(1) of Technical Code A of Schedule 8.3.

How generator governors help maintain frequency

A generator's governor regulates the amount of primary energy supply to a turbine (eg, hydro, gas, or steam) in response to variations in the power system's frequency. This adjusts the generator's output, with the amount and rate of adjustment determined by the size of frequency variation and the governor's characteristics and settings. Thus, a governor will typically respond to a fall in system frequency by automatically increasing generator output, and vice versa.[28] This action helps to stabilise (and potentially restore) system frequency movements away from 50 Hz

These three forms of frequency management are interrelated

3.17 Governor response is generally capable of being the fastest acting of the three frequency management mechanisms set out above. However, the extent and speed of governor response depends on the particular technology and how the governor (or alternative control mechanism) is configured. Real time energy dispatch is the slowest mechanism, while MFK responds continuously within the timeframe between fast automatic governor response and real time energy dispatch.

3.18 There is some overlap of the timeframes within which governor response, MFK, and energy dispatch respond to changes in system frequency. To this extent, the three forms of frequency management are inter-related. For example:

(a) MFK requirements can be influenced by:

(i) the choice of energy dispatch interval

(ii) the amount of governor response on the system

(b) it is feasible to have no specific MFK service, instead relying solely on governor response and energy dispatch to maintain normal frequency and system time error.[29]

3.19 Similarly, generators that do not have governors, or generators that have governors with limited frequency response, can affect frequency keeping requirements and cause a greater workload for other generators that have unrestricted governors.

The maintenance of frequency using system inertia

3.20 Although not a Code-mandated mechanism, the inertia of the New Zealand power system also plays a role in assisting the system operator to manage the power system's frequency, especially during severe frequency events. Inertia is the resistance of the power system to changes in frequency, which results from the masses of large spinning generators and motors taking time to slow down or speed up.

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28 Energy storage systems and demand response can provide similar functionality.

29 Noting that without frequency keeping, generators under governor control would move further from their dispatch levels or would need to be re-dispatched more often to keep generation in balance with demand.

What is system inertia?

System inertia refers to the energy stored in the rotating shaft of generators, motors and other industrial plant as they rotate at a speed that is synchronised to the power system's electrical frequency. Only synchronous machines store energy in this way – inverter-based resources do not inherently provide inertia.

Inertia is an integral part of power system operation. It helps the system operator manage the frequency of electricity across the power system. Inertia is particularly important for slowing the rate at which frequency changes due to a disturbance on the power system that affects the electricity demand / supply balance.

By slowing the rate of change of frequency, inertia helps to limit the size of frequency deviations, because there is more time for actions to stop the frequency deviation. The lower the inertia of a power system, the faster the rate of change of frequency and the larger the frequency deviation.[30]

Incentives and observed behaviours of parties around maintaining frequency

An apparent incentive to build generating stations exporting less than 30 MW

3.21 The Code says generating stations that export less than 30 MW to the transmission network or to a distribution or embedded network do not have to support system frequency in the same way as generating stations exporting 30 MW or more.[31] Upon application by the system operator, the Authority may direct that these smaller generating stations support system frequency in the same way as larger exporting generating stations, if the Authority is satisfied there is a benefit to the public.[32] However, to date the system operator has not applied to the Authority for the Authority to issue such a directive.

3.22 Hence, there is an incentive on generation owners to have generating stations that export less than 30 MW.

The Code is silent on frequency dead bands

3.23 Generation owners incur costs in the provision of governor response:

(a) generators are moved off their MW dispatch points, reducing generating plant efficiency (eg, cycling around, or operating away from, efficient loading levels)

(b) generating plant maintenance and lifecycle costs increase, from greater wear and tear caused by the generating plant's output changing constantly in response to changes in system frequency

30 For further elaboration, see section 10.5 of the FSR Phase 1 report prepared for the Authority by the system operator, available at https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Phase-1-final-report.pdf.

31 See clause 8.21 of the Code.

32 See clause 8.38 of the Code. The Code (Part 1) defines "benefit to the public" as meaning a public benefit net of any costs and detriments, including those detriments associated with a lessening of competition as those concepts are applied under the Commerce Act 1986.

(c) a generator's participation in the energy or instantaneous reserve markets may be constrained (eg, a generator constraining the operation of its generating unit(s) in order to provide upward or downward governor response capability).

3.24 In relation to the first two of these costs, the incentive on owners of generation with governors is to reduce the potential for such costs by applying a frequency response "dead band" to the generator's governor. Doing this stops the governor responding to any change in frequency that is within the frequency range specified by the dead band (eg, +/- 0.1 Hz). This improves the generator's efficiency and reduces wear and tear on the generator.

3.25 However, while benefiting the owner of the generating plant, a governor dead band reduces the generator's responsiveness to frequency deviations. The Code is silent on the use of frequency response dead bands, creating ambiguity over the extent to which generation owners may provide for them when specifying the capability of new generating units and then may subsequently use them.

3.26 The system operator is observing more and more generation owners applying frequency response dead bands to their generators' governors. This is degrading the system operator's ability to manage frequency within the normal band. It is also beginning to adversely affect the system operator's management of momentary fluctuations. The system operator may need to procure more instantaneous reserve to manage the frequency limits associated with contingent events.[33]

3.27 More prevalent use of governor dead bands may also be increasing the costs of governor response set out in paragraph 3.23 for generation owners who do not apply dead bands.

Some generation usually operates at its maximum MW capacity rating

3.28 The system operator observes that wind and geothermal generation usually operate at their maximum MW capacity rating if they have sufficient fuel (ie, wind and geothermal fluid). The implication of this operating behaviour is that this generation usually has no headroom to increase MW output to support the system operator in managing under-frequency. On the flip side, this generation is able to support the system operator in managing over-frequency.

Expected change to the status quo over the next 5–10 years

Expected technology change for parties who could help maintain frequency

3.29 Currently, synchronous controllable generating stations[34] produce approximately 90% of the energy delivered across the transmission network in New Zealand. The remaining 10% is produced by inverter-based variable and intermittent wind generating stations.[35]

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33 A contingent event is an event affecting the power system where the impact, the probability of occurrence, and the estimated costs and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event. See clause 12 of the Policy Statement, which is incorporated by reference in the Code under clause 8.10.

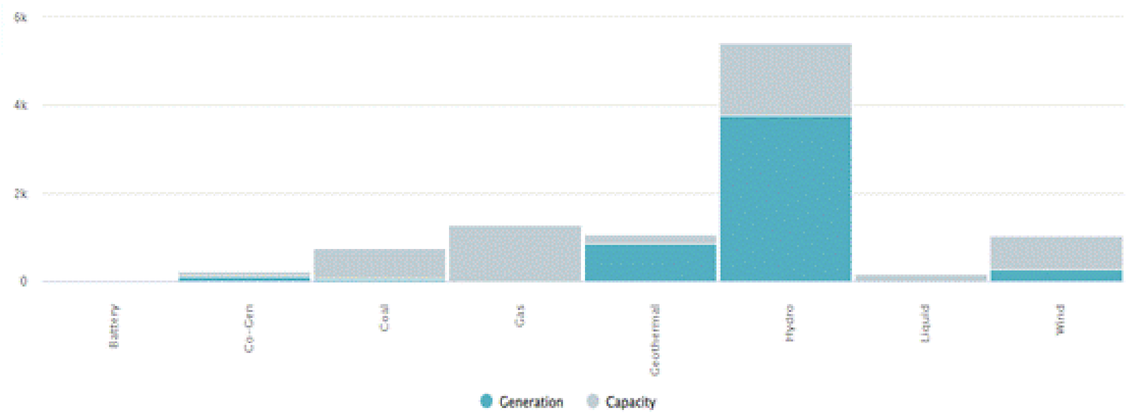
34 For the purposes of this paper, a controllable generating station means a generating station that relies on a resource that can be stored (eg, hydro, geothermal, gas, coal).

35 For the purposes of this paper:

- variable generation means generation that relies on a resource that is not stored and varies over time in a predictable manner (eg, the diurnal nature of solar PV generation)

Figure 1: Amount of generation capacity being used to produce electricity

Total generation by fuel type, updated in real time



Source: System operator

Notes: 1. Total generation as of 14:00 hours, 8 December 2022

3.30 The expectation is that, within five years, synchronous controllable generating stations will be producing substantially less of the energy delivered across the transmission network. This is because the composition of generation capacity is expected to be closer to 67% synchronous controllable generation and 33% inverter-based variable and intermittent resources within five years. There are two reasons for this expectation. First, connection requests received by the system operator indicate that in the next 3–5 years 88% of new generation capacity that is 10 MW[36] and above will be inverter-based variable and intermittent generation, and the remaining 12% will be synchronous controllable generation. Second, some large synchronous controllable generating units are expected to be retired over the next 10 years.

3.31 Inverter-based variable and intermittent generation is expected to, at times, comprise a larger percentage of dispatched generation (eg, during the middle of the day in summer and/or during windy periods over the summer). This is because of wind and solar PV generation having a lower marginal operating cost than thermal generation and, at times, hydro generation.

3.32 The amount of “behind-the-meter”[37] inverter-based variable and intermittent electricity generation has been increasing rapidly over recent years, albeit off a low base. This rapid uptake is expected to continue in the coming years, as the price of solar PV generation and battery technology continues to become more affordable for New Zealand consumers.

- intermittent generation means generation that relies on a resource that is not stored and varies over time in an unpredictable manner (eg, the effect of passing overhead clouds on solar PV generation).

36 A 10 MW threshold is used here because the system operator may require offers into the wholesale electricity market to be made for embedded generating stations greater than 10 MW in capacity.

37 Ie, generation located at an installation control point (ICP) that is consumed without being metered for the purpose of wholesale market settlement.

Defining the problem: Inverter-based resources cause more frequency fluctuations

More wind and solar PV generation makes system frequency more variable

3.33 With the forecast increase in the proportion of inverter-based variable and intermittent generation operating on the power system (ie, from increased wind and solar PV generation), it will become more challenging for the system operator to continuously balance the demand for, and supply of, electricity conveyed across the transmission network. More frequency fluctuations are likely over the next 5–10 years.

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

(a) a small imbalance between electricity demand and supply can cause deviations of frequency outside the normal band

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

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

3.36 Similar to wind generation, the intermittency of solar PV generation is affected by weather – mostly from cloud movement.[38] In addition, solar PV generation is also affected by its diurnal nature.

3.37 Intermittency of electricity generation output caused by clouds and wind creates difficulty for the system operator in predicting the amount of generation needed from one hour to the next in order to balance electricity demand and supply across the power system. The short-term (second-to-second) balancing of generation with electricity demand is also affected by fast changes in wind speed or cloud movement.[39] This presents a real challenge for the system operator to maintain frequency within the normal band of 49.8 Hz to 50.2 Hz.

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

(a) as load becomes more variable and elastic / flexible, and

(b) as this generation and embedded wind and solar PV generation displace the dispatch of synchronous generation that contributes to frequency regulation capability and system inertia.

3.39 Exacerbating this problem of more frequency fluctuations are:

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

(b) the expected relative increase in inverter-based variable and intermittent generation that either is not required to comply with the frequency-related

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

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

obligations in Part 8 of the Code or which receives a dispensation from needing to comply with the frequency-related obligations in Part 8

(c) the expected fall in system inertia as large thermal generating stations are retired over the coming years.

3.40 The next three subsections elaborate.

Some existing generation behaviour does not assist in managing frequency

3.41 The behaviour of some existing generation does not assist the system operator in managing frequency. As noted above, the system operator is observing the following behaviours amongst generators:

(a) Wind and geothermal generation usually operate at their maximum MW capacity rating if they have sufficient fuel. Therefore, this generation usually has no ability to increase MW output to support the system operator in managing under-frequency, but can support the system operator in managing over-frequency.

(b) More and more generation owners are applying frequency dead bands to their generators. This is degrading the system operator's ability to manage frequency within the normal band. It is also adversely affecting the system operator's management of momentary fluctuations.

3.42 Moving forward this will exacerbate the problem of more frequency fluctuations caused by increasing amounts of variable and intermittent generation on the power system.

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

3.43 Absent a change to Part 8 of the Code, the percentage of generation capacity needing to comply with the frequency-related obligations in Part 8 so as to assist in maintaining frequency within the normal band is anticipated to fall – at least for the foreseeable future. This is based on:

(a) the expected percentage increase in the number of generating stations exporting less than 30 MW to a network, due to the falling cost of solar PV generation and battery technology, which lends itself to smaller-scale installations deployed in a distributed manner across New Zealand's distribution networks for economic and resource availability reasons

(b) for the foreseeable future, the system operator continuing to grant dispensations to non-synchronous generating stations that have, or will have, assets or a configuration of assets that do not comply with a frequency-related AOPO or technical code.[40]

3.44 In accordance with clause 8.38 of the Code, the Authority could direct generating stations exporting less than 30 MW to a network to support system frequency in the same way as larger exporting generating stations, if the Authority was satisfied there was a benefit to the public. However, doing this on a station-by-station basis would be expected to have relatively high transaction costs.

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

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

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

3.45 The system operator could decline to grant non-synchronous generating stations a dispensation from the frequency-related obligations in Part 8 if the system operator—

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

(b) could not readily quantify the costs on other persons of the dispensation.[41]

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

(a) the characteristics of these non-synchronous generating stations (eg, an inverter-based resource using a frequency controller rather than a speed governor), and

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

3.47 At some point the system operator would be expected to stop granting these dispensations, because the cumulative effect of doing so *would be likely* to prevent the system operator operating the power system and meeting its PPOs.

A fall in system inertia is expected

3.48 Inverter-based variable and intermittent resources provide little or no system inertia. In many cases, these resources are replacing thermal generation in New Zealand. This reduction in system inertia means system frequency will change more rapidly in response to supply / demand imbalances. This in turn requires, for a given level of demand, an increased supply of resources for frequency keeping, instantaneous reserves and potentially automatic under-frequency load shedding (AUFLS).[42] Moving forward this fall in system inertia will exacerbate the problem of more frequency fluctuations caused by increasing amounts of variable and intermittent generation on the power system.

3.49 Currently, there is no specific procurement of, or payment for, inertia. Nor is some proportion of the cost of procuring instantaneous reserves and frequency keeping allocated to generators that do not provide inertia.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

3.50 In the absence of regulatory intervention, more frequency fluctuations outside the normal band are expected. Two case studies give an indication of the size of the problem—refer to Case study 1 and Case study 2 in Appendix A.

3.51 Case study 1 shows the effect of increasing amounts of inverter-based resources (using the example of wind generation) on frequency quality. Case study 2 looks at the impact

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

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

on the amount of instantaneous reserves needed and the operation of AUFLS as a result of wind generation displacing synchronous generation.

3.52 In summary, Case study 1 and Case study 2 point to:

(a) more wind generation adversely affecting frequency quality, with the connection of relatively large wind farms resulting in a material increase in the magnitude of frequency deviations

(b) increasing amounts of inverter-based resources possibly requiring the system operator to, in future, procure more instantaneous reserves to support frequency recovery in a significant grid event.

Who is affected by this problem and how?

3.53 In relation to this problem the key stakeholders are:

(a) consumers of electricity

(b) the system operator

(c) owners of existing generation

(d) investors in synchronous generation and inverter-based resources.

Table 1: Key stakeholders in relation to Issue 1

Key stakeholder	Reason
Consumers	Adversely affected by more frequent and larger frequency fluctuations, to the extent their electrical equipment operates sub-optimally or is damaged, thereby imposing economic costs on them. Consumers may also be adversely affected economically by the additional costs associated with the system operator managing system frequency (eg, procuring additional instantaneous reserve to cover less generator governor response on the power system).
System operator	Responsible under the Code for managing frequency. The identified problem makes it more difficult for the system operator to do this, for the reasons set out in the definition of the problem.
Owners of existing generation	Interested in the economic impacts of the identified problem (eg, equipment maintenance costs, profit foregone/gained from lost/additional energy sales due their generator governors picking up more/less of the burden of frequency management).
Investors in synchronous generation and inverter-based resources	Interested in the identified problem for economic reasons. Before investing they want certainty over what the regulator will do to address the identified problem.

Source: Electricity Authority

Identifying the root cause of the problem

Why existing regulatory arrangements will not address the problem

3.54 The identified problem of more frequent and larger frequency fluctuations will not be addressed by the existing regulatory arrangements because these arrangements do not contemplate the significant change in generation technologies over time. The regulatory arrangements were developed at a time when synchronous generation technology dominated the electricity sector.

3.55 Indeed, the Code currently is exacerbating the problem by, for example:

(a) permitting generating stations that export less than 30 MW to not have to support system frequency in the same way as larger exporting generating stations

(b) providing latitude in the frequency-related obligations in Part 8 for generators to deliver less governor response than would be economically efficient.

The problem relates to the design and implementation of regulatory arrangements

3.56 The identified problem relates to both the design and implementation of the Code. The Code could be clearer in specifying frequency-related obligations on generators. However, as noted in paragraphs 3.44 to 3.45 the Code does provide the Authority and the system operator with the ability to place frequency-related obligations on generators:

(a) in the case of the Authority, on generators that export less than 30 MW

(b) in the case of the system operator, on generators applying for a dispensation, by declining to grant the dispensation if the system operator—

(i) reasonably expects it cannot continue operating the existing power system and meet its PPOs, or

(ii) cannot readily quantify the costs on other persons of the dispensation.

Q1. Do you agree with the description of the first common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.

4 Issues 2, 3, 4: Inverter-based resources cause more voltage issues

4.1 This section describes three voltage-related issues that are expected to arise as more inverter-based variable and intermittent resources connect to the power system.

A description of the status quo

Key regulatory requirements for maintaining power system voltage

4.2 The Code promotes a stable power system by requiring voltage to be kept approximately uniform across the transmission network. Specifically, the Code requires a maximum voltage range of:

(a) +/-10% across assets that operate at 110 kV or 220 kV

(b) +/-5% across assets that operate at 50 kV or 66 kV.[43]

4.3 The Electricity (Safety) Regulations[44] require the voltage of electricity supplied to an installation to be:

(a) at 230–460 volts alternating current (AC) (standard low voltage) and kept within 6% of that voltage except for momentary fluctuations, for installations operating at a voltage of 200–250 volts AC[45]

(b) at a voltage agreed between the electricity retailer and the customer and kept within 6% of the agreed supply voltage unless the electricity retailer and customer agree otherwise, for installations operating at other than standard low voltage.[46,47]

4.4 New Zealand's adoption of 230 volts AC for standard low voltage is consistent with the International Electrotechnical Commission (IEC) standard IEC 60038. Most countries internationally have adopted this standard.

Key regulatory requirements for riding through transmission faults

4.5 The Code contains fault ride through standards for generators. The key elements of these standards are that generators connected to a network and whose assets are not disconnected by protection systems as the result of a transmission fault, must:

(a) ensure their assets remain stable and connected within the defined over voltage no-trip zone in Figure 2 during and immediately after faults on the HVDC link

(b) ensure their assets remain stable and connected within the over voltage and under voltage no-trip zones in Figure 3 during and immediately after AC faults on the transmission network

(c) ensure their assets generate reactive current to oppose changes in voltage that occur during and immediately after AC faults on the transmission network.[48]

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43 See clause 8.22 of the Code.

44 See regulation 28 of the Electricity (Safety) Regulations 2010.

45 Calculated or measured at the point of supply.

46 *Ibid*

47 The Authority notes the Electricity Networks Association has put a proposal to MBIE to increase the maximum allowable low voltage limit in New Zealand from 6% above 230 volts to 10% above 230 volts.

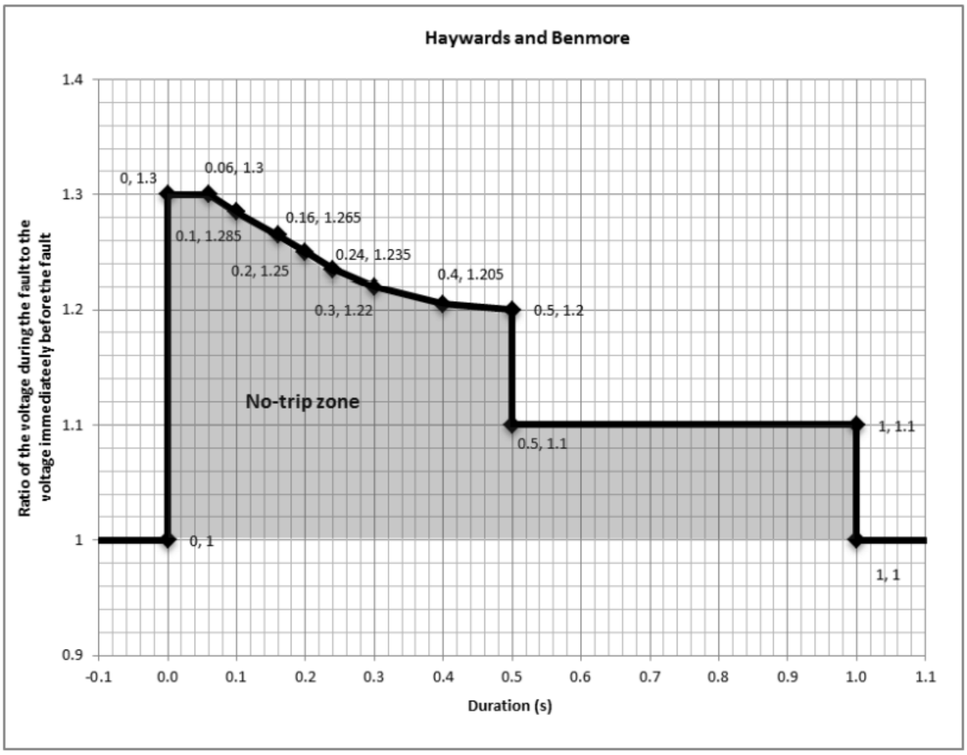
48 See clauses 8.25A and 8.25B of the Code.

4.6 The use of fault ride through standards for generators in New Zealand is consistent with the practice adopted by a number of jurisdictions internationally.

> **What is fault ride through?**
>
> Fault ride through refers to the ability of a generating unit to remain electrically connected to the network and operate in a stable manner during a transient voltage disturbance on the network (eg, a large drop in voltage accompanying a fault on the transmission network).

Figure 2: No-trip zone during permanent loss of the HVDC link

Voltage at Haywards 220 kV bus and Benmore 220 kV bus

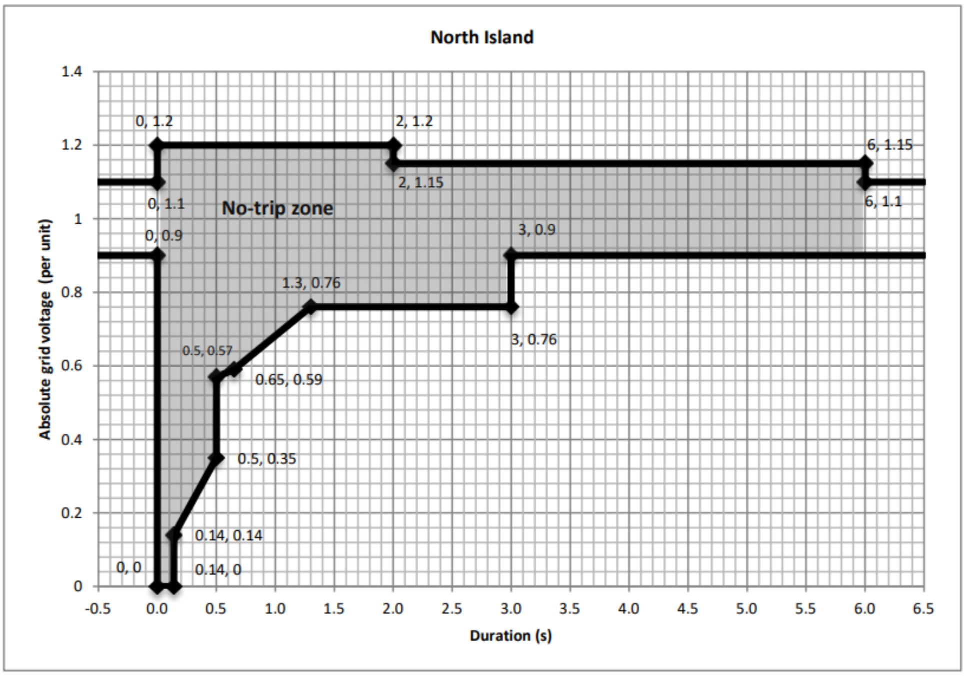


Source: Electricity Authority

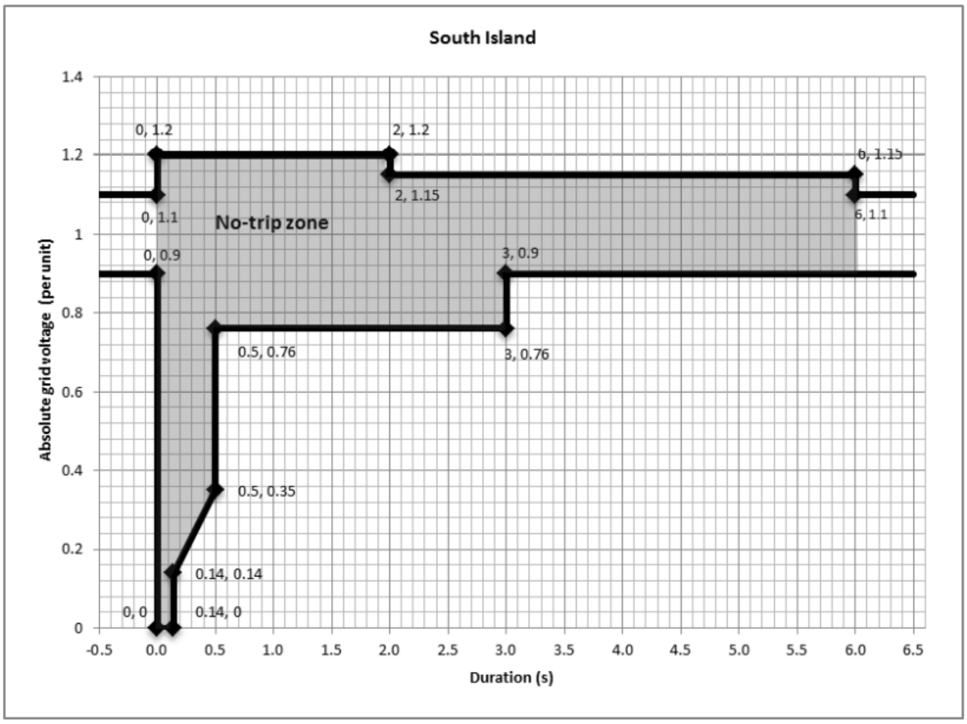
Notes: 1. See clause 8.25A of the Code.

Figure 3: No-trip zones during 110 kV and 220 kV transmission faults

North Island no-trip zone during 110 kV and 220 kV faults



South Island no-trip zone during 110 kV and 220 kV faults



Source: Electricity Authority

Notes: 1. See clause 8.25A of the Code.

Why it is necessary to maintain voltage and to ride through faults

4.7 There are three primary reasons why voltage must be maintained within the range of levels specified in the Code:

(a) to enable active power to flow across the power system

(b) to avoid equipment that produces, conveys or uses electricity being damaged and causing economic loss, and potentially physical harm

(c) to avoid cascade failure of the power system, caused by equipment disconnecting from the power system in order to avoid damage, which again results in economic loss and potentially physical harm.

4.8 There are two primary reasons for the fault ride through obligations in the Code:

(a) to reduce the risk of consumers losing electricity supply as a result of generation disconnecting from the power system due to—

(i) a large drop in system voltage during a fault on the transmission network

(ii) a large increase in system voltage due to a trip of the HVDC link

(b) to reduce the quantity of instantaneous reserve required to protect against loss of electricity injection from disconnected generation.

The mechanisms used to maintain voltage and to ride through faults

4.9 Power system voltage is maintained by balancing the demand for and production of reactive power. Electrical loads consume reactive power,[49] while generation and electrical devices such as capacitor banks, static synchronous compensators (STATCOMs) and static Volt-Amps reactive (VAR) compensators (SVCs) produce reactive power.[50]

4.10 Under normal circumstances, the system operator relies on electricity generators complying with the voltage-related obligations in Part 8 of the Code to provide reactive power and regulate voltage, and to ride through transmission disturbances (see paragraph 4.5).[51]

4.11 Synchronous generators are also a good source of fault current,[52] which is a parameter used to determine the level of system strength on the power system. A point on an electrical network with many generating units connected is considered to be a network location with high system strength, where voltage is very stable (ie, has very little deviation). A strong and stable generation connection point will allow equipment such as protection relays and inverters to operate correctly and stably.

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49 Including heavily loaded electrical networks.

50 STATCOMs and SVCs can produce and absorb reactive power.

51 See clauses 8.25A and 8.25B of the Code.

52 Fault current is electrical current flowing through a circuit during an electrical fault (short circuit) condition.

What is system strength?

System strength is a measure of the power system's ability to maintain voltage waveform and recover stably following a fault or disturbance on the system. System strength is important for:

- maintaining normal operation of the power system
- enabling dynamic response during a fault or disturbance on the system
- returning the system to an acceptable and stable operating condition after a fault or disturbance.

Low system strength can affect the power system's operation and cause system-wide disturbances. A power system with low system strength is more susceptible to a large voltage deviation and system instability should there be a fault or disturbance on the system. This will affect power quality and the operation of equipment connected to the power system, especially inverters which rely on a clean voltage waveform to function correctly.[53]

4.12 The Code does not specify voltage levels on distribution networks, or fault ride through requirements for generating stations that export less than 30 MW on distribution networks. However, the Code enables distributors to manage voltage on their networks via their connection and operation standards for distributed generation.[54]

Incentives and observed behaviours of parties around maintaining voltage and riding through faults

An apparent incentive to build generating stations on distribution networks

4.13 There appears to be a voltage-related incentive on generation owners to have generating stations that export to a distribution network or an embedded network, rather than to the transmission network. This is because the Code does not place explicit requirements on these generating stations to support system voltage in the same way as generating stations exporting to the transmission network.[55]

4.14 As noted in paragraph 4.12, the Code instead leaves it to distributors to specify any requirements[56] around supporting voltage on distribution networks, via their connection and operation standards for distributed generation. Distributors may also invest in voltage regulating assets to support parts of their networks that require additional voltage support.

Some generation usually operates at its maximum MW capacity rating

4.15 As noted in paragraph 3.28, the system operator observes that wind and geothermal generation usually operate at their maximum MW capacity rating if there is sufficient

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53 For further elaboration, see section 10.6 of the FSR Phase 1 report prepared for the Authority by the system operator, available at https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Phase-1-final-report.pdf.

54 See, for example, clauses 6.1(a), 6.2, 6.3(2) of the Code, and clauses 1D, 3(2), 9F and 18(2) of Schedule 6.1 of the Code, and clauses 3 and 11 of Schedule 6.2 of the Code.

55 See clause 8.23 of the Code.

56 That are additional to those in the Electricity (Safety) Regulations.

wind / geothermal fluid. The implication of this operating behaviour is that the generation may have little headroom to produce or absorb reactive power to help regulate voltage on the transmission network. In order to maintain system security, at times the system operator has to direct generators operating in this manner to reduce their MW output, to create sufficient headroom to support voltage on the transmission network.

An apparent incentive to build generating stations that export less than 30 MW

4.16 The Code says generating stations that export less than 30 MW to the transmission network or to a distribution or embedded network do not have to meet the fault ride through standards in Part 8 of the Code.[57] Upon application by the system operator, the Authority may direct that these smaller generating stations do have to meet the fault ride through standards, if the Authority is satisfied there is a benefit to the public.[58] However, to date the system operator has not applied to the Authority for the Authority to issue such a directive.

4.17 If the fault ride through standards in distributors' connection and operation standards for distributed generation are less onerous than the standards in Part 8, generation owners are incentivised to have distribution-connected generating stations that export less than 30 MW.

Testing difficulties reduce the incentive to ride through a fault

4.18 Generators must perform a fault ride through study to demonstrate that their assets can remain connected following a (three phase-to-ground) transmission fault. However, testing a generator's ability to ride through a fault can be very difficult, because an actual fault condition can be very different from the simulated test conditions. Hence, a generator's incentive to ride through a fault is reduced to the extent that the fault differs from that simulated in the generator's fault ride through study.

A non-AUFLS event reduces the incentive to ride through a fault

4.19 The instantaneous reserve procured by the system operator at any point in time is often sufficient to cover the tripping of a single generating unit that fails to ride through a transmission fault. This reduces the incentive on generators to ensure their assets remain connected during a transmission fault, as they are less likely to face an event charge for causing an under-frequency event.[59]

Expected change to the status quo over the next 5–10 years

Expected technology change for parties who could help maintain voltage and ride through faults

4.20 As noted in paragraphs 3.29 to 3.32:

(a) Currently, synchronous controllable generating plant produces approximately 90% of the energy delivered across the transmission network in New Zealand. The remaining 10% is produced by inverter-based variable and intermittent wind generating stations.

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57 See clause 8.21 of the Code.

58 See clause 8.38 of the Code. The Code (Part 1) defines "benefit to the public" as meaning a public benefit net of any costs and detriments, including those detriments associated with a lessening of competition as those concepts are applied under the Commerce Act 1986.

59 See clause 8.64 of the Code.

(b) The expectation is that, within five years, synchronous controllable generating stations will be producing substantially less of the energy delivered across the transmission network.

(c) Inverter-based variable and intermittent generation is expected to at times comprise a larger percentage of dispatched generation.

(d) Some large synchronous controllable generating units are expected to be retired over the next 10 years.

(e) The rapid uptake of "behind-the-meter" inverter-based variable and intermittent electricity generation is expected to continue in the coming years.

Defining the first voltage-related problem: Inverter-based resources cause greater voltage deviations

4.21 The first voltage-related problem is that inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows.

Having more inverter-based resources reduces system strength

4.22 In the absence of a change to the Code, the percentage of generation capacity required by the Code to assist in maintaining transmission voltage within the levels specified in Part 8 is expected to fall. This expectation is based on:

(a) a percentage increase in the number of generating stations exporting to New Zealand's distribution networks

(b) the amount of new solar generation installations expected in the next 5–10 years

(c) some large synchronous controllable generating units are expected to be retired over the next 10 years.

4.23 This expected fall will be more acute during daylight hours in the middle of summer when electricity demand is relatively low. During these times, smaller-scale solar generation with a zero or negligible marginal cost is likely to displace grid connected synchronous generation in the dispatch schedule.

4.24 New Zealand's power system is not tightly meshed and does not have very high short circuit levels compared with many overseas power systems.[60] Inverter-based resources, such as BESS's and wind and solar PV generators, provide less short circuit capability than synchronous generators. A reduction in the New Zealand transmission network's short circuit capability reduces its system strength.

Lower system strength causes larger voltage deviations

4.25 A fall in system strength on the transmission network reduces the transmission network's ability to maintain good quality voltage waveform and recover stably following the removal of a short circuit fault. A fall in system strength will result in larger system voltage deviations for any given fault or disturbance on the transmission network.

60 Ie, New Zealand's power system does not have very high electrical current flows through a circuit during an electrical fault.

Inadequate system strength may become an issue on New Zealand's transmission network in 3–7 years.[61]

4.26 As with the frequency-related obligations in Part 8 of the Code, the system operator could decline to grant a dispensation from the obligations in Part 8 related to maintaining voltage on the transmission network if the system operator—

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

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

4.27 However, again the system operator is expected to continue granting non-synchronous generating stations dispensations from assisting in maintaining voltage, for the foreseeable future. This is for the same reasons the system operator is expected to continue granting dispensations from the frequency-related obligations in Part 8 to non-synchronous generating stations for the foreseeable future.

The direction of distribution system voltage deviations is less clear

4.28 In contrast to voltage deviations on the transmission network, it is less clear whether voltage deviations on distribution networks will become larger or smaller as more variable and intermittent generation connects. This will depend on distributors':

(a) connection and operation standards for distributed generation

(b) connection and operation standards for demand customers, particularly for large loads

(c) investment in voltage-regulating assets

(d) real-time management of distribution network voltages.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

4.29 In the absence of regulatory intervention, voltage deviations outside the levels specified in the Code are expected. Two case studies give an indication of the size of the problem—refer to Case study 3 and Case study 4 in Appendix A.

4.30 Case study 3 shows that more distribution-connected generation can make regulating voltage at the GXP more challenging. Case study 4 gives examples of GXPs where the traditional direction of energy transfer is at times reversed, with energy being injected into the transmission network from the distribution network.

4.31 In summary, Case study 3 and Case study 4 point to increasing amounts of distributed generation resulting in the likelihood of:

(a) more GXPs having active power flowing from the distribution network to the transmission network for periods of the day

(b) the scheduling of more generators, SVCs or STATCOMs to absorb reactive power flowing from the distribution network to the transmission network, should voltage and reactive power not be adequately regulated on the distribution network.

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61 See p.56 of the 2022 report Future Security and Resilience: Implementing Activities for a Secure and Resilient Low-Emissions Power System, available at https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Phase-1-final-report.pdf.

Defining the second voltage-related problem: Inverter-based resources can cause network performance issues

4.32 The second voltage-related problem is that inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system.

Having more inverter-based resources reduces system strength

4.33 As noted in paragraphs 4.22 to 4.24, the forecast increase in the proportion of inverter-based variable and intermittent generation operating on the power system (ie, wind and solar PV) will cause a fall in the transmission network's system strength. This reduces the transmission network's ability to maintain good quality voltage waveform and recover stably following the removal of a short circuit fault. Inadequate system strength may become an issue on New Zealand's transmission network in 3–7 years.

Lower system strength can cause network performance issues

4.34 A distorted voltage waveform can cause maloperation of inverter controls, resulting in inverter-based resources performing in a manner that is less desirable from a network operations standpoint. In extreme cases, inverter-based resources disconnecting from the network in order to protect the inverter can cause under-frequency events.[62]

4.35 In addition, a reduction in system strength will increase the magnitude and frequency of voltage dips. This will require more voltage regulation capability to maintain the same level of voltage quality across the transmission network.

4.36 Also, low system strength reducing short circuit current during faults is more likely to result in the maloperation of protection relays. This could lead to the incorrect disconnection of transmission equipment, which at the extreme could potentially cause a widespread disturbance on the power system (eg, an AUFLS event or a widespread brownout or even blackout).

4.37 Stable and rapid voltage recovery is critical to avoiding cascade failure, particularly if large amounts of inverter-based resources are connected to the power system. The most common inverter-based resources used in New Zealand rely on a high quality system voltage waveform to determine the active and reactive power outputs that the inverter is capable of generating. These 'grid-following' inverters[63] are more likely to disconnect during a power system fault that causes a distorted voltage waveform than are synchronous generators. This is to protect the inverter from damage.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

4.38 In the absence of regulatory intervention, transmission network performance issues resulting from low system strength are expected. This is highlighted by Case study 5 in in Appendix A.

4.39 In summary, Case study 5 points to low system strength resulting in an increased likelihood of inverter-based resources disconnecting from the power system.

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62 See for example, North American Electric Reliability Corporation (September 2021), Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021 – Joint NERC and Texas RE Staff Report.

63 A 'grid-following' inverter tracks the voltage angle of the network to which it is connected, to control the output of the inverter-based resource and thereby remain synchronised with the network.

Defining the third voltage-related problem: Increasingly less generation subject to fault ride through obligations

4.40 The third voltage-related problem is that 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 30 MW to a network.

4.41 The New Zealand power system regularly experiences single and three phase AC faults on the transmission network that cause large voltage dips on that part of the system near to the fault location. Generating units across the power system experience varying reductions in voltage, depending on their electrical distance from the fault.

4.42 Similarly, the power system experiences HVDC link faults periodically. Generating units across the power system can experience large system over voltages depending on:

(a) their electrical distance from the HVDC converter stations, and

(b) the amount of power being transferred across the HVDC link.

4.43 There is expected to be a relative increase in inverter-based generation that either is not required to comply with the fault ride through obligations in Part 8 or which receives a dispensation from the obligation to comply with these obligations. This expectation is based on a percentage increase in the number of generating stations exporting less than 30 MW to a network. This in turn results from the falling cost of solar PV generation and battery technology, which lends itself to smaller-scale installations (see paragraph 3.32).

4.44 Therefore, the risk of 'sympathetic' tripping of generating units[64] during transmission faults is expected to increase with the forecast increase in the proportion of smaller scale inverter-based resources operating on the power system (eg, solar PV generation and BESS's). This, in turn, will increase the risk of frequency or voltage disturbances, and AUFLS events.

4.45 As with the frequency-related obligations in Part 8, the Authority could direct generating stations exporting less than 30 MW to a network to comply with the fault ride through obligations in Part 8, if the Authority considered there was a benefit to the public. However, doing this on a station-by-station basis would be expected to have relatively high transaction costs.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

4.46 Overseas experience shows there can be a systemic issue with inverter-based resources disconnecting from the network due to voltage-related issues caused by power system faults. This tripping offline of inverter-based resources is occurring for point-of-connection voltages within the power system's "no trip" zones. The issue is proving difficult to address for existing inverter-based resources because the inverter protection mechanisms causing the tripping are hard-coded in the inverter.[65]

4.47 Once inverter-based resources become the contingent event risk, it is likely that the amount of instantaneous reserve procured by the system operator to cover the risk of

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64 'Sympathetic' tripping of a generating unit occurs when the generating unit's protection equipment disconnects the unit from the network because of a disturbance on the transmission network.

65 North American Electric Reliability Corporation (September 2021), Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021 – Joint NERC and Texas RE Staff Report, p. vii.

'sympathetic' tripping of inverter-based resources will be inefficiently high. This would be because of the difficulty faced by the system operator in determining the size of the contingent event risk faced, in the absence of a good understanding of the technical characteristics of smaller-scale inverter-based resources.

4.48 The possibility exists that generating units may have to be operated sub-optimally due to system security constraints imposed by the system operator. This would reduce the return on investment for the owners of the generation, which may reduce the level of investment in inverter-based resources and potentially lead to less competition in the electricity market.

Who is affected by these problems and how?

4.49 In relation to these three voltage-related problems the key stakeholders are:

(a) consumers of electricity

(b) the system operator

(c) Transpower, as a transmission network owner

(d) distributors

(e) owners of existing generation

(f) investors in synchronous generation and inverter-based resources.

Table 2: Key stakeholders in relation to Issues 2, 3, and 4

Key stakeholder	Reason
Consumers	Face economic costs to the extent their electrical equipment operates sub-optimally or is damaged by greater voltage deviations or greater voltage / frequency instability. [66] They also face economic costs to the extent there are more power supply interruptions (AUFLS events) due to voltage / frequency events. Consumers may also be adversely affected economically by the additional costs associated with the system operator: (a) operating a transmission network that has greater voltage deviations (b) managing system voltage / system security.[67]
System operator	Responsible under the Code for managing voltage across the transmission network as well as system security. The identified problems make it more difficult for the system operator to do this, for the reasons set out in the definitions of the problems.

66 Over-voltage can damage insulation in electrical equipment, while under-voltage can cause excessive current to flow through electrical equipment.

67 For example:

(a) procuring additional instantaneous reserve to cover a higher risk of generators tripping due to greater voltage deviations / instability or less generator fault ride through on the power system

(b) constraining generation dispatch.

Key stakeholder	Reason
Distributors	Under the Commerce Act 1986 and the Electricity (Safety) Regulations, responsible for maintaining the quality of electricity conveyed across their networks. The identified problems make it more difficult for distributors to do this, for the reasons set out in the definitions of the problems.
Transpower as a transmission network owner	Responsible for planning and building its transmission network with enough capacity to deliver sufficient electrical power to consumers, using adequate reactive power compensation devices to regulate voltage across the transmission network and the necessary protective equipment to ensure faults are cleared correctly.
Owners of existing generation	Interested in the economic impacts of the identified problems. These may include: (a) equipment maintenance costs (b) costs associated with improved capability of voltage and reactive power control equipment in generating assets (c) system security constraints imposed by the system operator resulting in generating units being operated sub-optimally (d) profit foregone/gained from lost/additional energy sales due to generation being constrained on/off by a reduction in the transmission network's ability to transfer electrical power over longer distances.
Investors in synchronous generation and inverter-based resources	Interested in the identified problems for economic reasons. Before investing they want certainty over what the regulator will do to address the identified problems.

Source: Electricity Authority

Identifying the root cause of the problems

Why existing regulatory arrangements will not address the problems

4.50 The identified problems will not be addressed by the existing regulatory arrangements because these arrangements do not contemplate the significant change in generation technologies over time. The regulatory arrangements were developed at a time when synchronous generation technology dominated the electricity sector.

The problems appear to relate to the design of regulatory arrangements

4.51 The identified problems appear to relate to the design of the Code rather than how the Code has been implemented.

The Code places certain voltage support obligations on transmission-connected generators only

4.52 Currently, the Code requires only transmission-connected generators to, while synchronised:

(a) import or export reactive power from/to the transmission network within defined voltage ranges

(b) continuously operate in a manner that supports voltage and voltage stability on the transmission network in accordance with the technical codes in Part 8.[68]

4.53 Therefore, as distribution-connected generators make up an increasingly large percentage of generation in New Zealand, these key voltage support obligations will apply to relatively fewer generators, exacerbating the problem of greater voltage deviations across the transmission network.

4.54 As noted in paragraphs 4.12 to 4.14, the Code does not place explicit requirements on distribution-connected generating stations to support system voltage in the same way as generating stations exporting to the transmission network. Instead, the Code leaves it to distributors to specify any requirements[69] around supporting voltage on distribution networks, via their connection and operation standards for distributed generation.

4.55 Theoretically, well-considered connection and operation standards for distributed generation across all distribution networks in New Zealand should, in conjunction with the Part 8 voltage support obligations, minimise voltage deviations on the power system. However, the Authority is concerned about the extent to which all of the connection and operation standards in New Zealand will achieve this outcome as inverter-based resources become more prevalent. The rigour applied to the development of connection and operation standards may vary across distributors, as may the monitoring of network users' compliance with the standards.

The Code does not define technical requirements for inverters

4.56 Currently, the Code does not define technical requirements for inverters to limit the risk of inverter-based resources disconnecting during power system faults. As with voltage support on distribution networks, the Code leaves it to distributors to specify, via their connection and operation standards for distributed generation, any fault ride through requirements for inverter-based resources connected to, or seeking to connect to, a distribution network.

Part 8 places fault ride through obligations on larger generators only

4.57 Currently, Part 8 of the Code places fault ride through obligations on generating stations that export 30 MW or more. The Code leaves it to distributors to specify, via their connection and operation standards for distributed generation, any fault ride through requirements for generating stations that export less than 30 MW on distribution networks.

4.58 As smaller generating stations make up an increasingly larger percentage of generation in New Zealand, the fault ride through obligations in Part 8 of the Code will apply to relatively fewer generators. As noted in paragraph 4.44, this is expected to increase the risk of voltage or frequency disturbances and AUFLS events on the power system.

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68 See clause 8.23 of the Code.

69 That are additional to those in the Electricity (Safety) Regulations.

Q2. Do you agree with the description of the second common quality issue (ie, first voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.

Q3. Do you agree with the description of the third common quality issue (ie, second voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.

Q4. Do you agree with the description of the fourth common quality issue (ie, third voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.

5 Issue 5: There is some ambiguity around harmonics standards

5.1 This section describes the issue of there being some ambiguity around the applicability of harmonics standards.

A description of the status quo

Key regulatory requirements for electrical harmonics

5.2 Harmonics are sinusoidal waves superimposed on the primary AC 50 Hz sinusoidal waveform, with a frequency that is a (positive) multiple of 50 Hz.[70] The existence of harmonics means the voltage and current supplied by a power system is not a pure sinusoidal waveform – there is some distortion of the waveform.

5.3 Harmonics are typically caused by non-linear electrical loads, which are loads drawing current with a non-sinusoidal waveform (eg, computer switched mode power supplies,[71] variable frequency drives, arc furnaces). Inverter-based resources contain power electronic components that, if inadequately designed, can lead to excessive levels of current harmonics and voltage harmonics.[72]

5.4 Excessive levels of harmonics in electricity networks:

(a) lead to poor power quality—harmonics can adversely affect power quality both within the installation in which they are generated, and also within installations that share the same (electrically close) section of network (eg, the same substation)

(b) can cause problems in electrical appliances (eg, overheating, motor vibration, control equipment jitter)

(c) interfere with fixed line telecommunications—since the harmonic currents often oscillate at the same frequencies as the voice communications being transmitted over the phone line.

5.5 The Code and the Electricity (Safety) Regulations both contain harmonics standards that are intended to avoid harm associated with excessive harmonics.

5.6 The Benchmark Agreement, which is incorporated by reference in the Code, and which forms the basis for transmission agreements between Transpower and its customers[73] requires the parties to comply with:

(a) the New Zealand Electrical Code of Practice for harmonic levels (NZECP 36:1993), as amended from time to time, or

(b) any other equivalent or similar AS/NZS, IEC, IEEE standard, or

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70 For example, the 3rd harmonic is 3 x 50 = 150 Hz. The 5th harmonic is 5 x 50 = 250 Hz and so on.

71 A typical switched mode power supply for a computer transfers power from an AC source to the computer's direct current load.

72 Total harmonic distortion (THD), also known as Harmonic distortion factor (HDF), is the most popular index used to measure the level of harmonic distortion to voltage and current. THD is defined as the ratio of the root mean square (RMS) value of all harmonic components to the RMS value of the primary AC waveform. THD is usually expressed as a percentage.

73 Ie, generators, direct consumers, and distributors.

(c) any other requirements specified by Transpower (acting reasonably) that cover similar matters to those set out in NZECP 36:1993.[74]

5.7 The Code does not require other persons connecting, or connected, to the power system to comply with a harmonics standard, with one exception. Small-scale distributed generation[75] applying for connection to a distributor's network using the simplified one stage application process in Part 1A of Schedule 6.1 of the Code must comply with the standard AS/NZS 4777.2:2020.

5.8 However, Part 6 of the Code does empower distributors to specify, via their connection and operation standards for distributed generation, a harmonics standard for distributed generation wanting to connect, or which is connected, to their networks.[76] A recent informal review of distributors' connection and operation standards for distributed generation found distributors cite a version of AS/NZS 4777.2 for distributed generation of 10 kW or less.

5.9 The Electricity (Safety) Regulations require that the use of fittings and appliances must not unduly interfere with the satisfactory supply of electricity to any other person, or impair the safety of, or interfere with the operation of, any other fittings or appliances. This obligation is met by complying with whichever of the following standards is applicable:

(a) NZECP 36: 1993

(b) IEC 61000–3–2

(c) IEC/TS 61000–3–4

(d) IEC 61000–3–12.[77]

Why it is necessary to have up-to-date harmonics standards

5.10 There are three primary reasons why up-to-date harmonics standards are needed:

(a) to ensure standards are effective in limiting harmonic distortion caused by the latest technologies connected to electricity networks (eg, energy storage systems, electric vehicles, solar PV generation)

(b) to align standards with changes to the technologies used in power systems, so as to improve the measurement, assessment and mitigation of harmonic distortion

(c) to align standards with any changes in the operation of power systems, including the processes surrounding the connection of new users to the power system (eg, whether the harmonics of existing users are considered to be part of the background harmonic level in existence when a new user wishes to connect).

5.11 A further, but lesser, reason for up-to-date harmonics standards is to reduce costs by having in place better assessment guidelines, measurement techniques and arrangements for managing compliance.

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74 See clause 4.7 of Schedule 8 (Connection Code) of the Benchmark Agreement.

75 Those with a nameplate capacity of 10 kW or less in total.

76 See, for example, clauses 6.1(a), 6.2, 6.3(2) of the Code, and clauses 1D, 3(2), 9F and 18(2) of Schedule 6.1 of the Code, and clauses 3 and 11 of Schedule 6.2 of the Code.

77 See regulation 31.

The mechanisms used to avoid excessive levels of harmonics

5.12 The two main mechanisms used to avoid excessive levels of harmonics are:

(a) designing the inverter to minimise distortion in the sinusoidal waveform produced (eg, by incorporating a transformer in the power output stage or selecting higher quality power electronic components)

(b) installing harmonic filters that mitigate harmonics through the use of capacitors and inductors, or by injecting equal and opposite frequencies to the harmonic.

Incentives and observed behaviours of parties around avoiding excessive harmonic levels

Incentive on small-scale distributed generators[78] to mitigate their harmonics

5.13 Owners of small-scale distributed generation[79] incorporating an inverter have a one-off incentive to mitigate any harmonics generated, through the use of inverters that comply with the harmonic limits specified in the standard AS/NZS 4777.2:2020. Doing so enables these distributed generators to apply for connection to a distributor's network using a simplified one stage application process (Part 1A in Schedule 6.1).

Incentive on HVDC owner to mitigate the HVDC link's harmonics

5.14 The HVDC owner has an incentive to manage the HVDC link's harmonics so as to avoid the possibility of the system operator constraining the HVDC link's power transfer to avoid the HVDC link's harmonics adversely affecting the transmission network.

Expected change to the status quo over the next 5–10 years

Expected technology change for parties who could help avoid excessive harmonic levels

5.15 As has already been noted, there is expected to be a significant increase over the next 5–10 years in the number of inverter-based resources connected to the power system – particularly distribution networks. This will increase the amount of harmonic distortion across the power system.

5.16 At the same time, system strength on the transmission network is expected to fall, as over time transmission-connected generators represent a smaller percentage of electricity supplied in New Zealand. This will have the effect of increasing harmonic distortion in New Zealand's transmission and distribution networks.

Defining the problem: Some ambiguity around harmonics standards

The governance of harmonics standards may not promote power quality

5.17 As noted in paragraphs 5.6 and 5.9, currently harmonics standards are located in the Electricity (Safety) Regulations and in transmission agreements applying terms in a document incorporated by reference in the Code (the Benchmark Agreement). As noted in paragraph 5.8, distributors can also specify a harmonics standard in their connection

78 Under Part 6 of the Code a distributed generator is someone who owns or operates, or intends to own or operate, generating plant that is connected, or is proposed to be connected, to a distribution network or to a consumer installation that is connected to a distribution network.

79 Distributed generation with a nameplate capacity of 10 kW or less in total.

and operation standards for distributed generation, under the empowering provisions in Part 6 of the Code.

5.18 The Code is subordinate to Acts and regulations,[80] so any harmonics standards in the Code, or authorised by it, are subordinated to the harmonics standards in the Electricity (Safety) Regulations if and where the Code and these regulations conflict. The existence of differing harmonics standards in the Code and the Electricity (Safety) Regulations may not promote power quality, to the extent that industry participants adopt the wrong standard due to confusion over which standard is applicable.

5.19 The same harmonics standard (NZECP 36:1993) is referred to in the Electricity (Safety) Regulations and the Benchmark Agreement, which on the face of it should lower the risk described in the previous paragraph. However, as noted in paragraph 5.6, the Benchmark Agreement also provides for other equivalent or similar standards to be adopted, and for Transpower to specify any other requirements that cover similar matters to those set out in NZECP 36:1993. The Electricity (Safety) Regulations do not provide Transpower with such discretion.

5.20 A further source of potential confusion over harmonics standards is the Electricity (Safety) Regulations applying two different standards (NZECP 36:1993 and IEC 61000-3-2) to equipment covered by the standard (AS/NZS 4777.2) referred to in Part 6 of the Code and in distributors' connection and operation standards for distributed generation. Since NZECP 36:1993 applies to all consumer installations, it applies to the same inverter equipment as does AS/NZS 4777.2. So too does the standard IEC 61000-3-2, which applies to electrical and electronic equipment with a rated input current up to and including 16 amps per phase, and intended to be connected to public low-voltage distribution systems.[81]

5.21 Lastly, the Electricity (Safety) Regulations refer to a standard that is in fact not to be regarded as an International Standard (IEC/TS 61000–3–4[82]) according to the International Electrotechnical Commission.[83]

Ambiguity around managing the flow of harmonics through a GXP

5.22 Currently there is no agreed limit on the flow of harmonics through a GXP, whether from the transmission network to the distribution network or vice versa. There is a need to understand the amount of harmonic current / emissions through a GXP that will result in distribution network operation and transmission network operation not being adversely affected. A starting point is assessing the extent of harmonics at GXPs at the present time. Currently, there is insufficient information to do such an assessment.

5.23 There is then the question of how best to manage the flow of harmonics through a GXP. The system operator cannot do anything to manage harmonics on distribution networks that flow through a GXP into the transmission network. The system operator can at best require harmonic filters on the transmission side of the GXP, which has economic efficiency implications (eg, the allocation of the cost of these filters).

80 See section 33(2) of the Electricity Industry Act 2010.

81 Arc welding equipment that is not professional equipment, with a rated input current up to and including 16 amps per phase, is included in IEC 61000-3-2. Arc welding equipment intended for professional use, as specified in IEC 60974-1, is excluded from IEC 61000-3-2 and can be subject to installation restrictions as indicated in IEC 61000-3-12.

82 Correctly referred to as IEC TS 61000-3-4:1998.

83 https://webstore.iec.ch/publication/4151.

5.24 Similarly, distributors face the same issue in relation to harmonics flowing through a GXP from the transmission network. Distributors can only seek to manage harmonics on their side of the GXP, again through the use of harmonic filters, and again with economic efficiency implications related to the allocation of the cost of these filters.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

5.25 In the absence of regulatory intervention, power quality issues caused by harmonics are expected to arise over the coming years, requiring the installation of equipment such as harmonics filters and reactors.

5.26 As noted in paragraph 5.4, harmonics can, in addition to causing power quality issues, also cause problems in electrical appliances and interfere with fixed line telecommunications. These problems could have material economic implications, ranging from shortening the life of electronic devices and electrical equipment such as power transformers, motors and generators, to the mis-operation and tripping of circuit breakers on electrical networks.

5.27 The size of this harmonics problem is directly related to the uptake of inverter-based resources. The more inverter-based resources within the power system, the more acute the harmonic distortion will become.

Who is affected by this problem and how?

5.28 In relation to this problem the key stakeholders are:

(a) consumers of electricity

(b) the system operator

(c) Transpower, as a transmission network owner

(d) distributors

(e) owners of existing generation

(f) investors in synchronous generation and inverter-based resources.

Table 3: Key stakeholders in relation to Issue 5

Key stakeholder	Reason
Consumers	Adversely affected by harmonics, to the extent their electrical equipment operates sub-optimally or is damaged, thereby imposing economic costs on them.
System operator	Has responsibilities under the Code for the real time co-ordination and delivery of common quality and dispatch across the transmission network.[84] The identified problem makes it more difficult for the system operator to do this, for the reasons set out in the definition of the problem.

84 See clause 7.1 of the Code.

Key stakeholder	Reason
Distributors	Interested in the economic impacts of the identified problem (eg, equipment maintenance costs and, potentially, equipment damage).
Transpower as a transmission network owner	Responsible for meeting all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of the Code.[85]
Owners of existing generation	Interested in the economic impacts of the identified problem (eg, equipment maintenance costs and, potentially, equipment damage).
Investors in synchronous generation and inverter-based resources	Interested in the identified problem for economic reasons. Before investing they want certainty over what the regulator will do to address the identified problem.

Source: Electricity Authority

Identifying the root cause of the problem

Why existing regulatory arrangements will not address the problem

5.29 The identified problem will not be addressed by the existing regulatory arrangements because these arrangements:

(a) create ambiguity and uncertainty over the applicability of harmonics standards

(b) do not address the management of harmonics at GXPs.

The problem appears to relate to the design of regulatory arrangements

5.30 The identified problem appears to relate to the design of the Code and the Electricity (Safety) Regulations, rather than how they are implemented.

5.31 Currently, the Code and the Electricity (Safety) Regulations contain overlapping and inconsistent harmonics standards. Also, the Code does not define arrangements for managing harmonics at GXPs.

Q5. Do you agree with the description of the fifth common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.

85 See clause 12.21 of the Code.

6 Issue 6: Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system

6.1 This section describes the issue of network operators having 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. In this context the term "network operators" refers to the system operator and distributors.

A description of the status quo

Key regulatory requirements for sharing of asset-related information with network operators

6.2 The Code requires certain information to be provided to:

(a) the system operator about assets[86] that are intended to be connected, or that are connected, to the transmission network

(b) distributors about distributed generation that is intended to be connected, or that is connected, to distribution networks.[87]

6.3 The general policy underpinning the provision of such information may be summarised as follows:

(a) To assist the system operator in—

(i) planning to comply, and complying, with its PPOs in Part 7 of the Code, and

(ii) achieving the dispatch objective in Part 13 of the Code.[88]

(b) To enable distributors to decide whether the connection of distributed generation to their respective networks (including via consumer installations) is consistent with distributors' connection and operation standards.[89]

Why it is necessary to share asset-related information with network operators

6.4 The main reason why it is necessary to share information with network operators on assets wanting to connect, or which are connected, to the power system is to provide for the safe, reliable and economically efficient operation of the power system. The system operator and distributors play an important role in managing the reliability and the

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86 The Code defines an "asset" to mean equipment or plant that is connected to or forms part of the transmission network. In the case of Part 8 of the Code, an asset includes equipment or plant that is *intended* to become connected to the transmission network and equipment or plant of an *embedded generator*.

An embedded generator is someone who owns or operates one or more generating units that are directly connected to a local network or an embedded network and that inject into the local network or embedded network at a single point of injection.

87 For the purposes of this issues paper, the equipment or plant of a distributed generator is referred to as an asset. This is reasonable given that an embedded generator's equipment or plant is an asset for the purposes of Part 8 of the Code, and the terms "embedded generator" and "distributed generator" are very similar in meaning.

88 See clause 8.25(4) of the Code.

89 See clauses 6.2 and 6.3 of the Code.

security of electricity delivered to consumers. To enable the modelling, monitoring and management of system reliability and security, the system operator and distributors require knowledge of resources that:

(a) can adversely affect power system reliability and security

(b) can provide services to support power system reliability and security.

The mechanisms for sharing asset-related information with network operators

6.5 Various mechanisms are used for sharing information on assets wanting to connect, or which are connected, to the power system. These include:

(a) the use of supervisory control and data acquisition (SCADA) systems to enable the real-time monitoring of assets that are important to managing the power system

(b) the use of the wholesale information and trading system (WITS) to provide the system operator with:

   (i) energy bid and energy/reserve offer information (eg, maximum generator output and ramp rates, price/quantity bands)

   (ii) forecasts of generation potential for intermittent generating stations[90]

(c) an application maintained by the system operator, which enables:

   (i) asset owners to submit and update information on commissioned, modified, or decommissioned assets

   (ii) asset owners to provide the system operator with information on their outages

   (iii) each North Island AUFLS provider to provide the system operator with their feeder configuration and annual load profile data

(d) the registry of ICPs, which contains various ICP information, including:

   (i) physical address

   (ii) the type of installation—whether electricity is consumed, generated, or both consumed and generated, at the ICP

   (iii) if the ICP connects the distributor's network to distributed generation:

      1. the nameplate capacity of the distributed generation; and

      2. the generation fuel type of the distributed generation

   (iv) the plant name for any embedded generating station at the ICP.

Incentives and observed behaviours of parties around sharing asset-related information with network operators

6.6 The system operator has observed that some asset owners can be reluctant to share information on their assets with the system operator. This could be due to various factors—for example:

(a) concerns related to the confidentiality of the information

[90] See clauses 13.22 and 13.18A of the Code.

(b) ambiguity around information sharing obligations

(c) resourcing constraints

(d) other organisational priorities.

Q6. If you are a distributor, what is your experience of asset owners sharing information with you for network operation purposes?

Expected change to the status quo over the next 5–10 years

Expected technology change for assets wanting to connect, or which are connected, to the power system

6.7 There is expected to be a significant increase over the next 5–10 years in the number of DERs connected to the power system – particularly distribution networks. There is also expected to be an increase in controllable loads—for example, controllable hot water, energy storage systems, and smart appliances.

6.8 DERs are expected to be mainly converter-based resources (eg, solar PV generation, energy storage systems, electric vehicles). Converter-based resources encompass both inverters (which convert DC electricity to AC electricity) and rectifiers (which convert AC electricity to DC electricity). The technology used in converter-based resources is evolving, as equipment manufacturers work to improve it. This contrasts with the stable nature of the technology used in synchronous generators.

Defining the problem: Insufficient information on assets wanting to connect, or which are connected, to the power system

An expected fall in generating stations needing to provide information about intended output

6.9 There is expected to be a percentage decrease in generating stations for which the system operator receives information regarding intended output.

6.10 The Code says if the system operator considers it necessary to assist the system operator in planning to comply, and complying, with its PPOs and achieving the dispatch objective, the system operator may require an embedded generator to provide:

(a) information regarding the intended output of each embedded generating station greater than 10 MW in capacity

(b) the information required under paragraph (a)—

(i) as an offer in accordance with subpart 1 of Part 13 of the Code, or

(ii) in a form and manner agreed between the system operator and the embedded generator.[91]

6.11 As noted above, inverter-based variable and intermittent resources are expected to comprise a larger share of New Zealand's generation capacity over the coming years. The fall in the relative cost of these technologies, coupled with New Zealand moving

91 See clause 8.25 of the Code.

towards 100% renewable electricity generation, means it is expected that a larger share of generation in New Zealand will be less than 10 MW (eg, solar PV generation and energy storage systems installed by commercial and industrial consumers).

6.12 This will reduce the percentage of embedded generation for which the system operator has information regarding intended output, which in turn is expected to impair the system operator's ability to operate the transmission network securely and efficiently.

6.13 Distributors also face challenges operating their networks due to insufficient information on the output of distribution-connected generation. Amongst other things this affects their ability:

(a) to plan for and manage network congestion

(b) manage the quality (eg, the voltage) of electricity conveyed across their networks.

6.14 This issue faced by distributors is expected to become worse as more generation connects to distribution networks over the coming years.

Ambiguity as to what asset-related information is to be shared

6.15 Currently there is ambiguity around the Code obligation on asset owners to share certain information about their assets with the system operator. As noted in footnote 86, an asset is any equipment or plant that is connected to or forms part of the transmission network and, in the case of Part 8, includes:

(a) equipment or plant that is intended to become connected to the transmission network, and

(b) equipment or plant of an embedded generator.[92]

6.16 Differing interpretations exist as to what constitutes being connected to the transmission network. For example:

(a) Is it only equipment or plant that is physically connected directly to the transmission network at a point of connection?

(b) Is it equipment or plant that forms part of a contiguous network that has one or more points of connection with the transmission network?

Inconsistency across technologies in the sharing of asset-related information

6.17 Currently, wind generators do not have to carry out periodic testing of their generating units.[93] 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.

An issue with proprietary asset-related information

6.18 The technology used in inverter-based resources is very flexible and configurable. As noted above, it is also evolving. This makes it important for network operators to have up-to-date accurate asset information available to them, in order to plan and operate the power system in a safe, reliable, and efficient manner.

92 See clause 1.1(1) of the Code.

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

6.19 With inverter technology evolving, equipment manufacturers are reluctant to release sufficiently detailed information for network operators to perform detailed power system analysis. In the absence of information and knowledge on the performance of inverter-based resources, the system operator will operate the transmission network in a more conservative manner than is necessary. This is to mitigate the unknown risk of economic loss for consumers and industry participants due to a potential power system disturbance caused or exacerbated by inverter-based resources.

6.20 Distributors are expected to adopt a similar approach, for the same reason as the system operator.

Greater demand-side flexibility risks inefficient use of resources

6.21 Currently, electricity demand-side behaviour is relatively passive and predictable. Empowered by evolving technologies, greater demand-side flexibility is expected. This offers potential benefits (eg, the need for less peaking generation and network investment in peaking capacity).

6.22 However, network operators need to know they can rely on particular demand-side behaviour(s) occurring. Absent this information, to meet reliability standards network operators will be incentivised to use resources for whose behaviour / services they have good knowledge / information. This risks the inefficient use of the electricity sector's demand-side and supply-side resources.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

6.23 As New Zealand moves towards 100% renewable electricity generation, continuously matching electricity demand and supply, and managing contingencies, are expected to require:

(a) the owners/operators of assets connected to the power system to share more information about their assets with network operators (eg, demand / generation status, equipment performance during power system disturbances)

(b) more coordination between the system operator and distributors over the real-time operation of the power system (eg, to maintain an optimal voltage profile across the power system).

6.24 In the absence of regulatory intervention, there will be an increased probability of frequency and voltage instability on New Zealand's power system, and possibly more AUFLS events. New Zealand's transmission network cannot be operated in isolation from distribution networks, and vice versa. As more generation and flexible demand connect to distribution networks, the potential will increase for these assets to adversely affect the power system, in terms of frequency instability and voltage variation and, to a lesser extent, the reliable supply of electricity.

6.25 If the sharing of information on these assets does not improve, the uncertainty surrounding the performance, availability and intended use of these assets will result in the system operator and distributors increasing their operational risk mitigation measures. In turn this will lead to the inefficient use of economic resources—for example:

(a) inefficiently high amounts of instantaneous reserves procured to manage the unknown risk of inverter-based resources tripping during network disturbances

(b) unoptimised dispatch of generation (including self-dispatch of small-scale distributed generation), due to generation and/or dispatchable load being constrained on/off.

Who is affected by this problem and how?

6.26 In relation to this problem the key stakeholders are:

(a) consumers of electricity

(b) the system operator

(c) Transpower, as a transmission network owner

(d) distributors

(e) owners of existing generation

(f) investors in synchronous generation and inverter-based resources.

Table 4: Key stakeholders in relation to Issue 6

Key stakeholder	Reason
Consumers	Adversely affected by the additional costs they face from the system operator procuring inefficiently high amounts of instantaneous reserves to manage the unknown risk of inverter-based resources tripping during disturbances on the transmission network. Also face economic costs to the extent that there is greater voltage or frequency instability and/or more AUFLS events due to network operators having insufficient information on assets wanting to connect, or which are connected, to the power system.
System operator	Has responsibilities under the Code for the real time co-ordination and delivery of common quality and dispatch across the transmission network. The identified problem makes it more difficult for the system operator to do this efficiently and to facilitate the efficient operation of the New Zealand electricity market, for the reasons set out in the definition of the problem.
Distributors	Under the Commerce Act 1986 and the Electricity (Safety) Regulations, are responsible for maintaining the quality of electricity conveyed across their networks. Insufficient information about assets connecting, or which are connected, to distribution networks makes it more difficult for distributors to do this, for the reasons set out in the definition of the problem.
Transpower as a transmission network owner	Responsible for meeting all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of the Code.[94]

94 See clause 12.21 of the Code.

Key stakeholder	Reason
Owners of existing generation	Interested in the economic impacts of the identified problem (eg, profit foregone/gained from lost/additional energy sales due to generation being constrained on/off due to network operators having insufficient information about assets connected to the power system; wind generators not having to undertake routine testing).
Investors in synchronous generation and inverter-based resources	Interested in the identified problem for economic reasons. Before investing they want certainty over what the regulator will do to address the identified problem.

Source: Electricity Authority

Identifying the root cause of the problem

Why existing regulatory arrangements will not address the problem

6.27 The identified problem will not be addressed by the existing regulatory arrangements because these arrangements do not contemplate the significant change in generation technologies over time. The regulatory arrangements were developed at a time when synchronous generation technology dominated the electricity sector. The existing regulatory arrangements are also premised inherently on electricity demand being relatively passive and predictable.

The problem appears to relate to the design of regulatory arrangements

6.28 The identified problem appears to relate to the design of the Code rather than how it is implemented.

6.29 The Code could be clearer in specifying the information that asset owners must share with the system operator and distributors, including proprietary information.

6.30 Currently, the Code does not define sufficiently what information the system operator and distributors should be sharing with each other to promote the safe, reliable and efficient operation of the power system in a world with significant amounts of inverter-based resources.

Q7. Do you agree with the description of the sixth common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.

7 Issue 7: Some Code terms missing or not fit for purpose

7.1 This section describes the issue of the Code:

(a) containing some terms that appear to not be fit for the purpose of appropriately enabling technologies

(b) omitting some terms that would help enable technologies.

A description of the status quo

7.2 Part 8 of the Code was drafted some 20 years ago. The range of technologies used in New Zealand's electricity industry at that time represented a subset of the range of technologies in use today and probably over the coming years. Some clauses and terms used in Part 8 still reflect the technological environment of 20 years ago.

Defining the problem: Code terms missing or not fit for purpose

Terms used in Part 8 of the Code enable only a subset of technologies

7.3 The range of technologies covered by Part 8 of the Code represents a subset of the technologies used in the electricity industry. In particular, a number of clauses in Part 8 are drafted on the basis that only synchronous generating technologies are in use. Examples of terms used in Part 8 that do reflect the modern range of electricity industry technologies include:

(a) SVCs being treated as though they are the only devices that provide dynamic reactive power compensation, which is not the case (eg, STATCOMs and static synchronous series compensators (SSSCs) provide this compensation)[95]

(b) generating units being treated as always having a speed governor, which is not the case (eg, solar PV generation; batteries that are discharging).[96]

Some existing definitions appear not fit for purpose

7.4 Various terms used in Part 8 of the Code are defined. This is to avoid regulatory ambiguity and improve operational efficiency. These defined terms are set out in Part 1 of the Code.

7.5 Some definitions appear to not be fit for the purpose of appropriately enabling technologies. Examples include:

(a) Not distinguishing between intermittent generation and variable generation—the Code defines only "intermittent generating station" and "intermittent generator"

(b) Ambiguity over the use of the defined term "point of connection" and undefined terms such as "connected", "directly connected", and "indirectly connected".[97]

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95 See clause 9 of Appendix B of Technical Code A in Schedule 8.3 of the Code.

96 See clause 5 of Technical Code A in Schedule 8.3 of the Code.

97 See, for example, the definitions of "point of connection", "connection location", "grid interface", "embedded network", "embedded generating station", "generating station", "generator", "ICP", clauses 8.15, 8.25, 8.25A, 8.54B of the Code, clauses 2, 4, 5, 6 and 7 of Technical Code A of Schedule 8.3 of the Code, clauses 7 and 9 of Technical Code B of Schedule 8.3 of the Code, and Appendix A of Technical Code C of Schedule 8.3 of the Code.

There appear to be some missing definitions

7.6 The Code appears to be missing some definitions necessary for achieving the purpose of appropriately enabling technologies. Examples include:

(a) Defining what is meant by inverter-based resources

(b) Defining what is meant by “grid forming” and “grid following” inverters

(c) Defining what is meant by “virtual generation” and “virtual load”

(d) Defining what is meant by “asynchronous” generation.

Assessing the size of the problem

Adverse outcomes are expected in the absence of regulatory intervention

7.7 In the absence of regulatory intervention, there will be an increased probability of power system inefficiencies and electricity market inefficiencies. These are expected to be in the form of:

(a) reduced competition between technologies (eg, generation technologies, voltage support technologies)

(b) operational inefficiencies (eg, the need for the system operator to exempt inverter-based resources from certain asset testing requirements applicable only to synchronous generation).

Who is affected by this problem and how?

7.8 In relation to this problem the key stakeholders are:

(a) consumers of electricity

(b) the system operator

(c) Transpower, as a transmission network owner

(d) distributors

(e) owners of existing generation

(f) investors in synchronous generation and inverter-based resources.

Table 5: Key stakeholders in relation to Issue 7

Key stakeholder	Reason
Consumers	Are expected to face economic costs to the extent that the Code enabling a subset of electricity industry technologies results in: (a) reduced competition between technologies (eg, generation technologies, voltage support technologies) (b) operational inefficiencies in the electricity industry (eg, the need for the system operator to exempt inverter-based resources from certain asset testing requirements applicable only to synchronous generation).

Key stakeholder	Reason
System operator	Has responsibilities under the Code for the real-time co-ordination and delivery of common quality and dispatch across the transmission network. The identified problem makes it more difficult for the system operator to do this efficiently and to facilitate the efficient operation of the New Zealand electricity market, for the reasons set out in the definition of the problem.
Distributors	Under the Commerce Act 1986 and the Electricity (Safety) Regulations, are responsible for maintaining the quality of electricity conveyed across their networks. The identified problem makes it more difficult for distributors to do this efficiently, for the reasons set out in the definition of the problem.
Transpower as a transmission network owner	Responsible for meeting all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of the Code.[98]
Owners of existing generation	Interested in the economic impacts of the identified problem (eg, profit foregone/gained from the Code enabling a subset of technologies).
Investors in synchronous generation and inverter-based resources	Interested in the identified problem for economic reasons. Before investing they want certainty over what the regulator will do to address the identified problem.

Source: Electricity Authority

Identifying the root cause of the problem

Why existing regulatory arrangements will not address the problem

7.9 The identified problem will not be addressed by the existing regulatory arrangements because these arrangements do not contemplate the significant change in electricity industry technologies over time. In particular, the regulatory arrangements were developed at a time when synchronous generation technology dominated the electricity sector.

The problem appears to relate to the design of regulatory arrangements

7.10 The identified problem appears to relate to the design of the Code rather than how it is implemented.

7.11 The Code enables only a subset of technologies.

98 See clause 12.21 of the Code.

Q8. Do you agree with the description of the seventh common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.

Q9. Do you consider there to be other high priority common quality issues not identified in this paper that are occurring or that you expect to occur because of:

a. the uptake of inverter-based resources, and/or

b. how the Code enables different technologies?

Appendix A Case studies

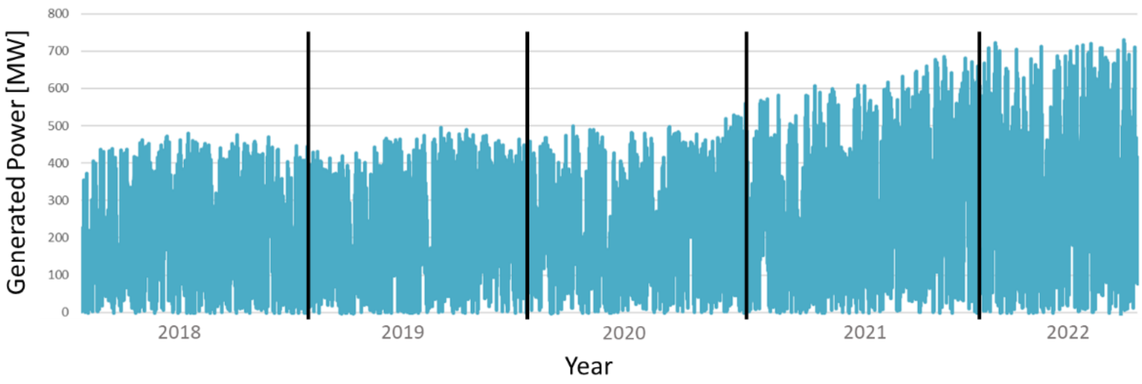
A.1 This appendix contains five case studies. The first two case studies provide an indication of the size of the frequency-related issue described in the main body of this paper. The remaining case studies provide an indication of the size of the first two voltage-related issues described in the main body of this paper.

Case study 1: The effect on frequency of increasing amounts of wind generation

A.2 Case study 1 shows the effect of increasing amounts of inverter-based resources (using the example of wind generation) on frequency quality.

A.3 The amount of power generated by wind in the North Island was relatively constant from early 2018 until late 2020. This is shown by Figure 4. The commissioning of two wind farms in the North Island in late 2020 and mid-2021 increased North Island wind generation by approximately 250 MW. [99]

Figure 4: North Island wind generation from 2018 to mid-2022



Source: System operator

A.4 The effect of this additional wind generation on frequency has been considered in three ways:

(a) Scenario 1: looking at the quality of frequency before and after the commissioning of the two wind farms

(b) Scenario 2: looking at how regions of New Zealand with significant wind generation affect frequency in comparison to regions with low wind penetration

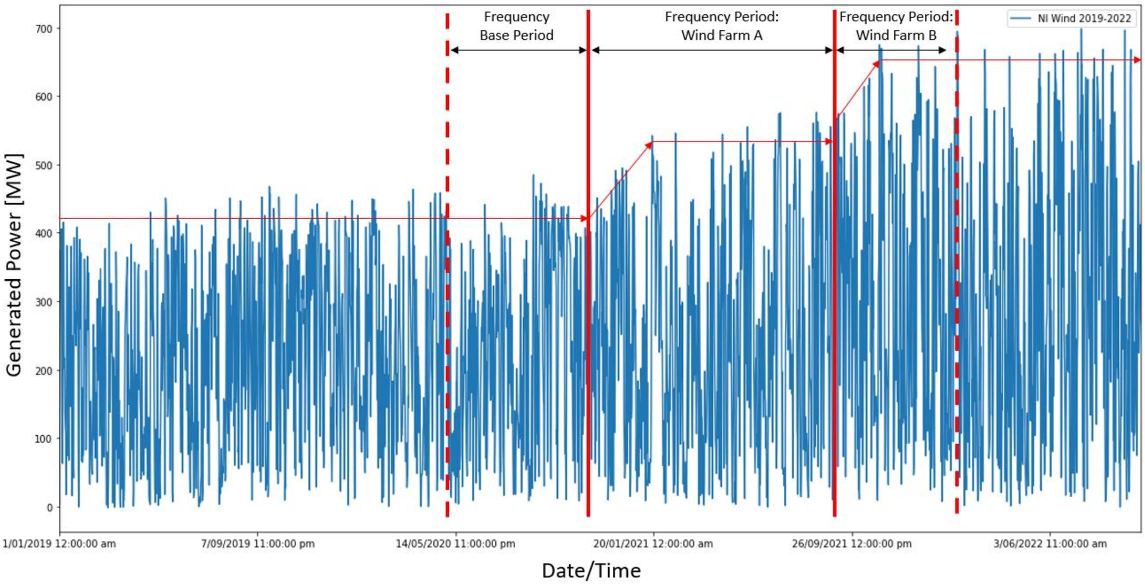
(c) Scenario 3: comparing frequency quality under a relatively high percentage of synchronous generation with frequency quality under a relatively low percentage of synchronous generation.

99 As measured by combined maximum continuous output.

Scenario 1: Frequency quality before and after commissioning of two wind farms

A.5 As Figure 5 shows, a noticeable increase in the magnitude of frequency deviations occurs after the connection of Wind Farm A in 2020, with a further noticeable increase in the magnitude of frequency deviations after Wind Farm B is commissioned in 2021.

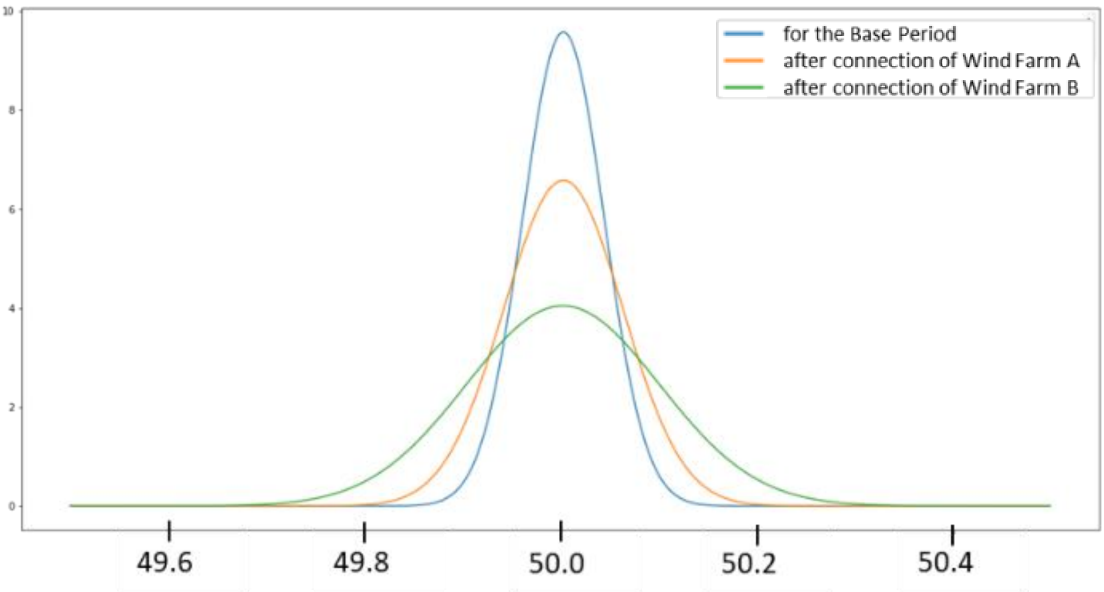
Figure 5: Magnitude of frequency deviations from 2019 to mid-2022



Source: System operator

A.6 The increase in the standard deviation in Figure 6 shows higher variability of frequency within the normal band following the commissioning of the two wind farms.

Figure 6: Frequency quality pre- and post-commissioning of two wind farms



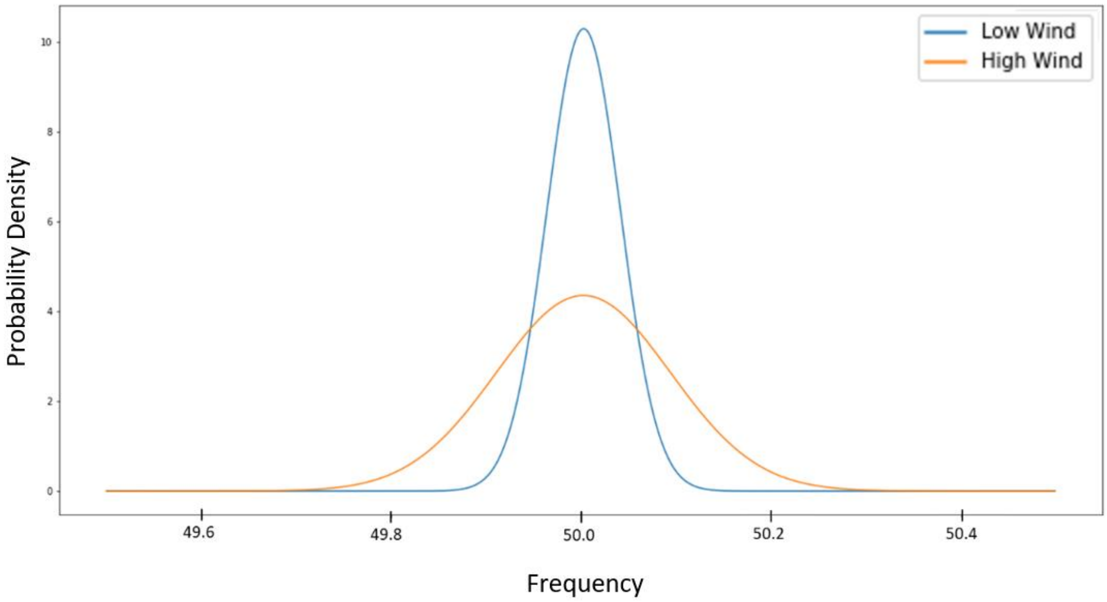
Source: System operator

Scenario 2: How high wind penetration affects frequency

A.7 The effect of high wind penetration on frequency quality has been assessed by looking at frequency in 2021 during periods of high and low wind generation output in four North Island regions with significant installed wind generating capacity.[100] Active power output from wind generating stations is highly correlated within each region, but not necessarily across the regions. This reflects the different wind patterns across New Zealand. Taking a regional approach to looking at the effect of wind generation on frequency quality removes the effect of diversity of wind generation from the analysis.

A.8 As Figure 7 shows, frequency quality under high wind penetration is poorer than frequency quality under low wind penetration.

Figure 7: Impact on frequency quality of regions with significant wind generation



Source: System operator

Scenario 3: Comparison of frequency quality under high and low synchronous generation

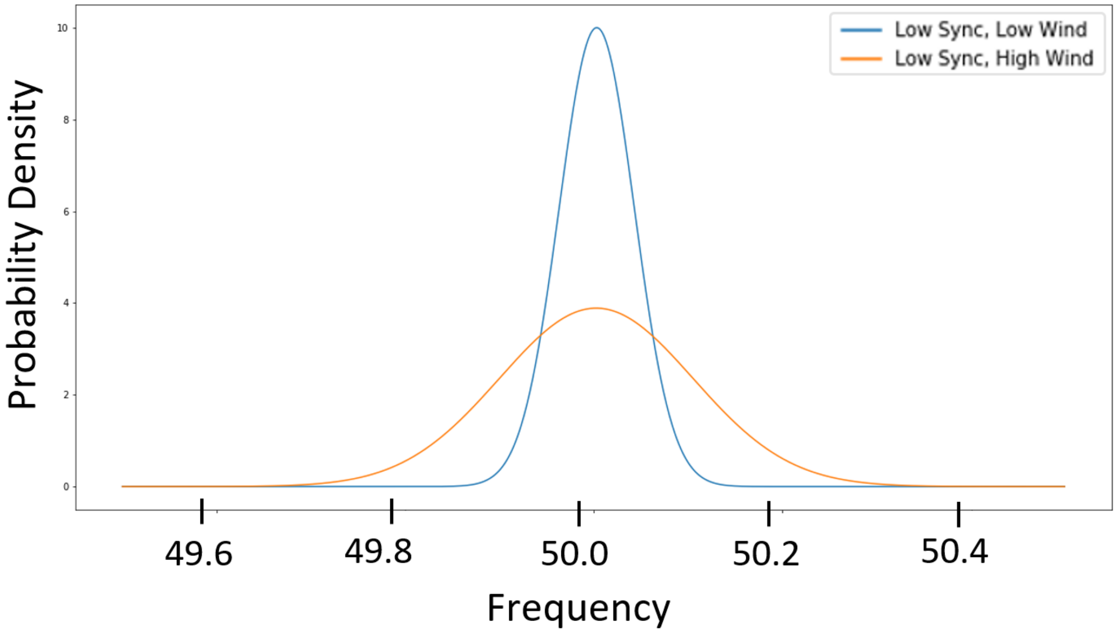
A.9 The effect on frequency of a relatively low percentage of synchronous generation has been assessed by comparing frequency quality over the period January to March 2021 against frequency quality over the period April to September 2021.

A.10 The former period has relatively lower amounts of synchronous generation injecting into the transmission network, while the latter period has relatively higher amounts of synchronous generation injecting into the transmission network. As Figure 8 shows, frequency quality improves with higher amounts of synchronous generation injecting into the transmission network.

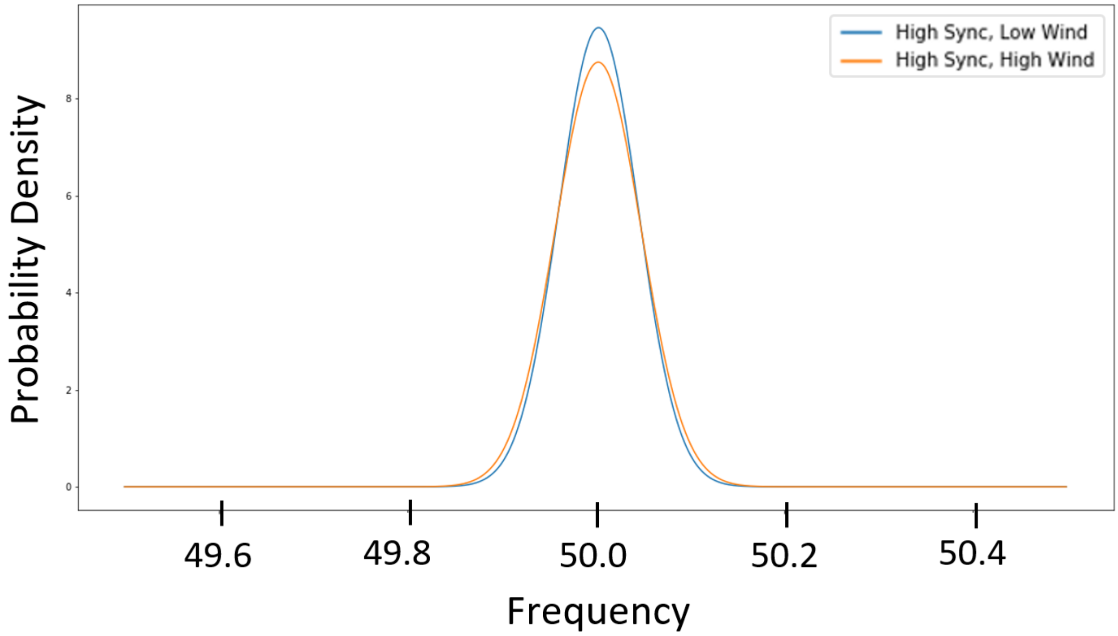
100 Manuwatu, Taranaki, Waikato, and Wellington.

Figure 8: Effect on frequency quality of less connected synchronous generation

Lower synchronous generation



Higher synchronous generation



Source: System operator

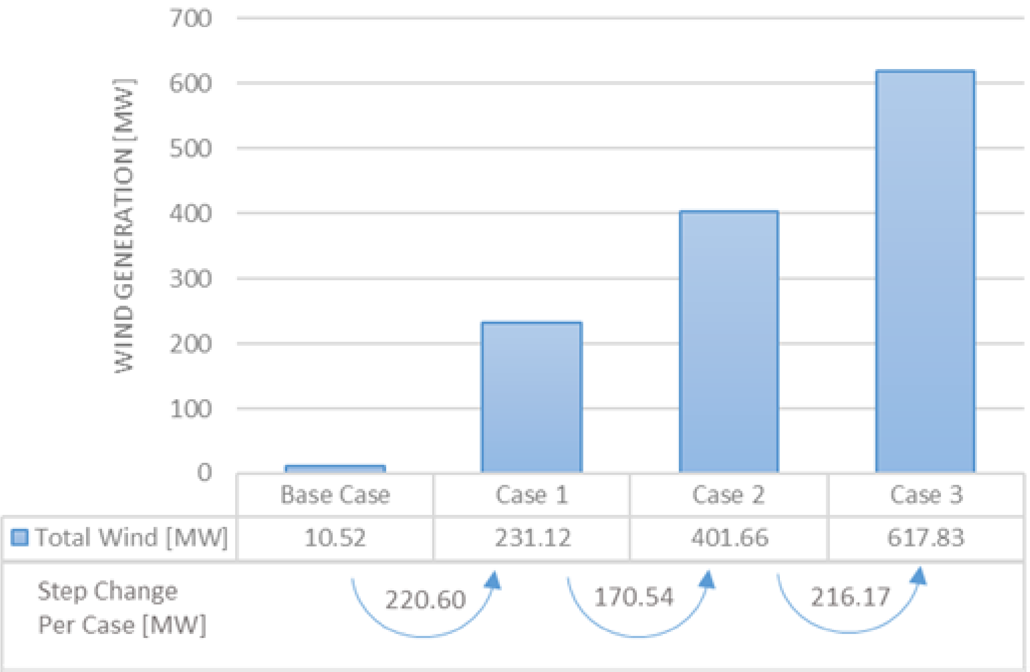
A.11 The conclusion from Case study 1 is that increased wind generation adversely affects frequency quality.

A.12 While these frequency variations and observed trends are small currently, the trend observed is expected to continue with increased amounts of inverter-based resources connected to the power system in coming years.

Case study 2: The impact of wind generation on instantaneous reserves and AUFLS operation

A.13 Case study 2 considers the potential impact on the required amount of instantaneous reserves and the operation of AUFLS,[101] as a result of wind generation displacing synchronous generation. For this case study, a real time case file has been used, with wind generation displacing synchronous generation per Figure 9.

Figure 9: Increase in wind generation in Case study 2



Source: System operator

A.14 Using this case file, a scenario has been run involving the disconnection of 432 MW of generation, with frequency observed for a period of 60 seconds following the disconnection.

A.15 Figure 10 shows the results, which are that for the same system condition the nadir point decreases due to an increase in the rate of change of frequency (ROCOF), as more wind generation connects to the power system. This is attributed to the decrease in system inertia that results from directly displacing synchronous generation with wind generation. This points to the frequency nadir point trending lower over time as more inverter-based resources are connected to the power system.

A.16 The higher ROCOF may affect the operation of AUFLS if the higher ROCOF is outside the design parameters of the AUFLS scheme. AUFLS is designed to trip blocks of electrical load to arrest a significant fall in frequency and prevent cascade failure of the power system. The tripping of each block of load is triggered at a certain frequency. Blocks do not trip instantly at these trigger frequencies, but instead trip after a certain delay.

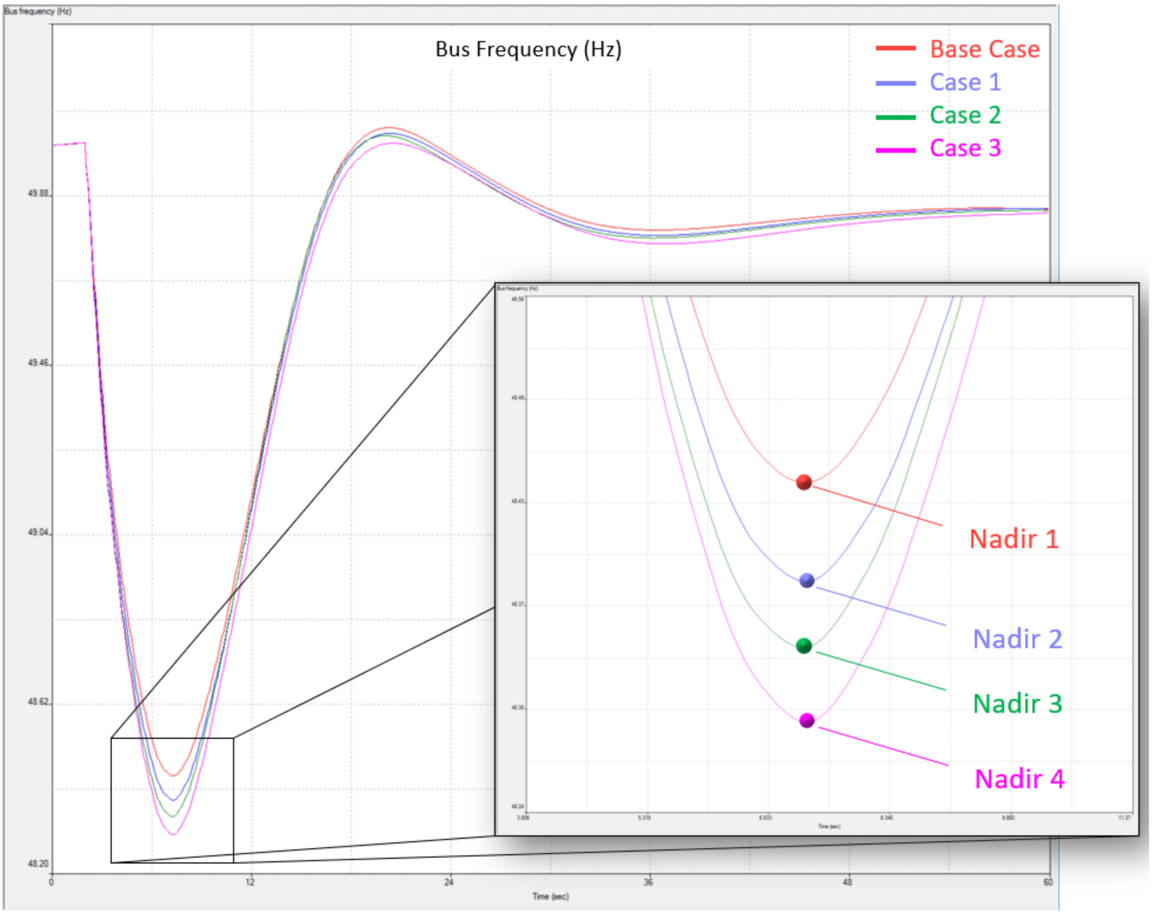
101 Under the current 2-block AUFLS scheme.

A.17 Case study 2 indicates that increasing amounts of inverter-based resources may, in the future, require the procurement of more instantaneous reserves to support frequency recovery in a significant grid event.

A.18 Although the case study considers wind generation, the case study is equally applicable to other inverter-based resources that control the response of the inverter to grid events in the same way as wind generation.

Figure 10: Frequency deviation with 432 MW of generation disconnection

Frequency trace following a disturbance of 432 MW for cases of synchronous generation displaced by existing wind energy



Source: System operator

Case study 3: Challenges regulating voltage at a GXP with more distribution-connected generation

A.19 Case study 3 shows that more distribution-connected generation can make regulating voltage at the GXP more challenging.

A.20 Electrical loads consume active and reactive power. Under normal operating scenarios, active and reactive power flows from the transmission network to the distribution network, via the GXP, to supply demand.

A.21 A distribution network with significant reactive power sources (eg, underground cables, distributed generation that is generating reactive power) may push reactive power into the transmission network. Typically, this is more likely to occur:

(a) during periods of light load demand on the distribution network

(b) during periods when distributed generation output on the distribution network is sufficiently high to cause active power flows from the distribution network to the transmission network.

A.22 The system operator can schedule generators, reactors, SVCs, or STATCOMs to absorb reactive power flowing from the distribution network to the transmission network, in order to keep voltage within the transmission network's operational limits. For example, Islington GXP has many SVCs installed, enabling the system operator to manage the voltage at the GXP within a consistent range (1–1.03 per unit (pu)). This is shown in Figure 11.

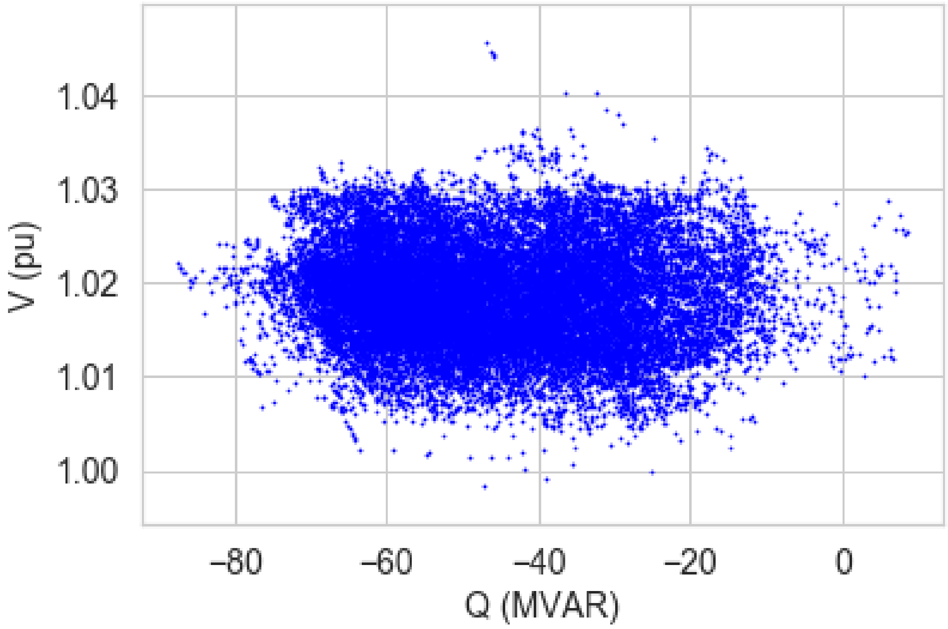
A.23 In contrast, the Kopu GXP, which exhibits similar reactive power export behaviour as the Islington GXP, has no reactive power or voltage regulation capability in close proximity. Therefore, voltages at the Kopu GXP increase more significantly than at Islington as reactive power flows from the distribution network to the transmission network increase. The voltage at the Kopu GXP ranges from 0.99 pu to 1.05 pu.

A.24 With more distribution-connected generation in the future, more reactive power is likely to be injected into the transmission network through GXPs if voltage and reactive power are not adequately regulated at the distribution network level. This will result in greater voltage deviations at different points on the transmission network. The magnitude of some of these deviations will be exacerbated in places by the planned retirement of transmission-connected generation over the coming years.

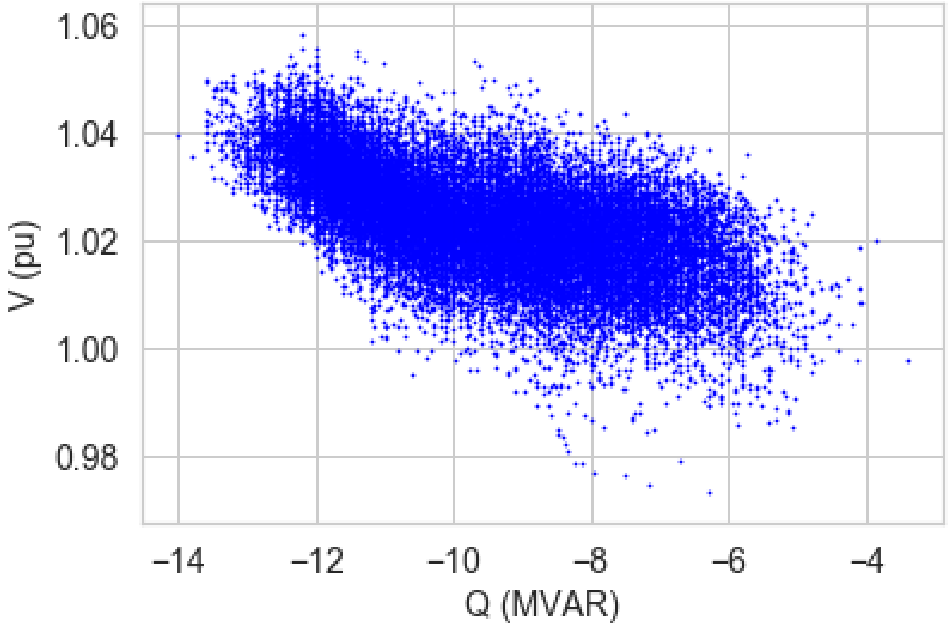
A.25 Figure 12 provides an alternative view of the relative sensitivity of the voltage at the Islington and Kopu GXPs to variations in reactive power at the GXPs. The voltage range at Kopu is within 3% for 90% of the time, while at Islington the voltage range is narrower – within 2% for 90 % of the time – reflecting the Islington GXP's voltage regulation capability.

Figure 11: Voltage ranges at the Islington and Kopu GXPs

Voltage and reactive power at the Islington GXP (Bus: ISL_66 kV_AV)



Voltage and reactive power at the Kopu GXP (Bus: KPU_110 kV_AV)

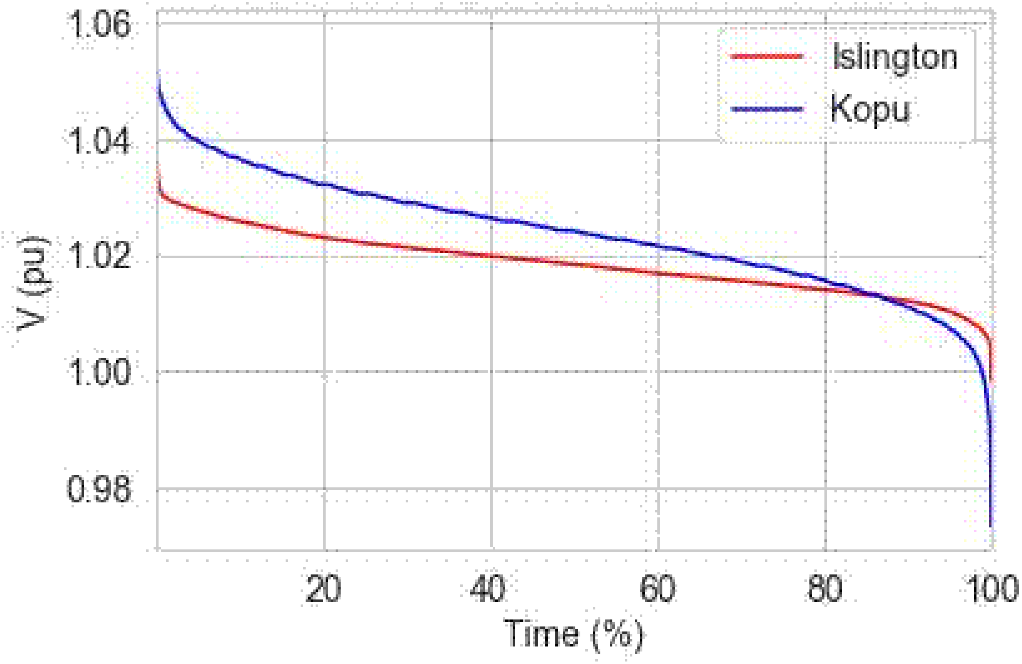


Source: System operator

Notes: 1. The negative values on the horizontal axis represent reactive power flows from the distribution network to the transmission network.

Figure 12: Voltage duration curves for the Islington and Kopu GXPs

Voltage load duration curves for the Islington GXP (Bus: ISL_66 kV_AV) and the Kopu GXP (Bus: KPU_110 kV_AV)



Source: System operator

Case study 4: Examples of GXPs where energy is being injected into the transmission network

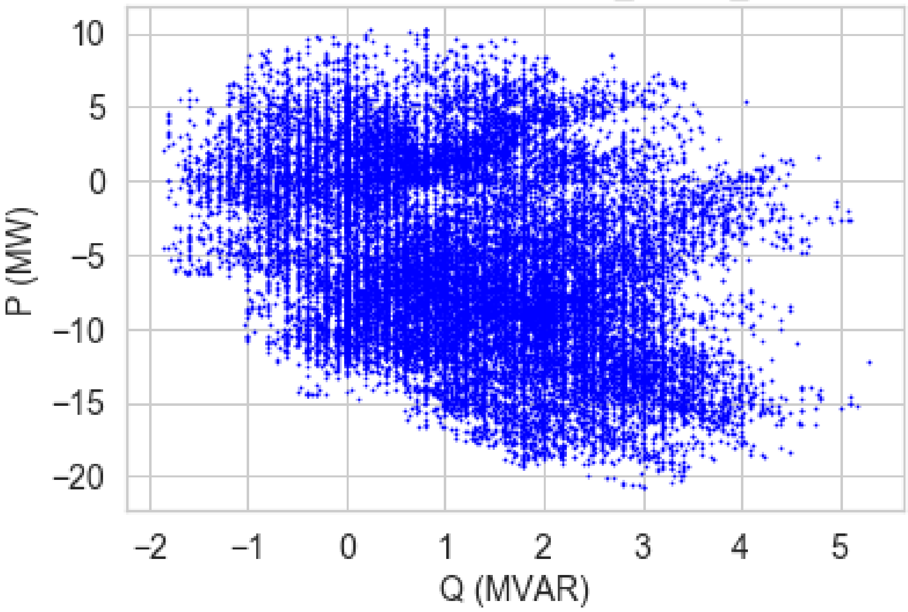
A.26 Case study 4 gives examples of GXPs where the traditional direction of energy transfer is at times reversed, with energy being injected into the transmission network from the distribution network.

A.27 If, at a GXP, energy flows from the distribution network to the transmission network, then this can affect the flow of reactive power and pose challenges in managing voltage at the GXP. During periods of high active power flows from the distribution network to the transmission network, reactive power flows can be difficult to forecast, as highlighted by the scatter plot graphs in Figure 13. This makes it difficult to manage voltage on the transmission network.

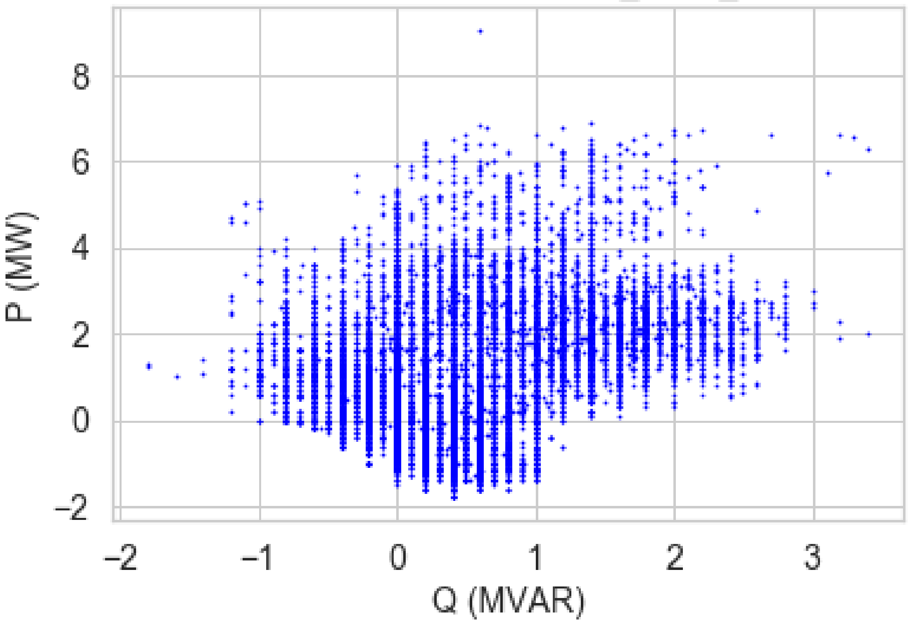
A.28 With more distribution-connected generation in the future, especially solar PV generation, it is likely that we will see more of these examples (eg, during the middle of sunny summer days). In addition to the voltage-related challenges described above, this will also pose a challenge for the system operator in maintaining the generation and demand balance. The system operator will need to factor these reverse power flows through GXPs into the load forecasts used in scheduling generation for dispatch.

Figure 13: Voltage ranges at the Clyde and Dobson GXPs

Active and reactive power at the Clyde GXP (Bus: CYD_220 kV_AV)



Active and reactive power at the Dobson GXP (Bus: DOB_66 kV_AV)



Source: System operator

Notes:

1. The positive values on the vertical axis represent active power flows from the transmission network to the distribution network
2. The negative values on the vertical axis represent active power flows from the distribution network to the transmission network
3. The positive values on the horizontal axis represent reactive power flows from the transmission network to the distribution network
4. The negative values on the horizontal axis represent reactive power flows from the distribution network to the transmission network.

Case study 5: Low system strength adversely affects voltage regulation and quality

A.29 Case study 5 highlights that low system strength is expected to increase the likelihood of inverter-based resources disconnecting from the power system, resulting in transmission network performance issues.

A.30 System voltage will change for a given imbalance in reactive power caused by demand changes or the sudden disconnection/connection of equipment such as power transformers. In this way, changes in voltage on the power system are similar to changes in frequency, where an imbalance in the generation of, and/or demand for, active power will cause frequency deviations.

A.31 A GXP with many generators or transmission circuits connected to it generally has high system strength. A high system strength GXP exhibits smaller voltage deviations than a GXP with low system strength. This is shown by the comparison in Figure 14.

A.32 The Pakuranga GXP is considered to have high system strength, with many transmission circuits connected to it and being electrically close to major North Island power stations. Voltage at this GXP is regulated within a small range (0.99–1.025 pu).

A.33 In comparison, the Hororata GXP is considered to have low system strength with four 66 kV circuits connected to the GXP and limited short circuit current contribution from remote power stations. The system strength of the Pakuranga GXP is 12 times that of the Hororata GXP.

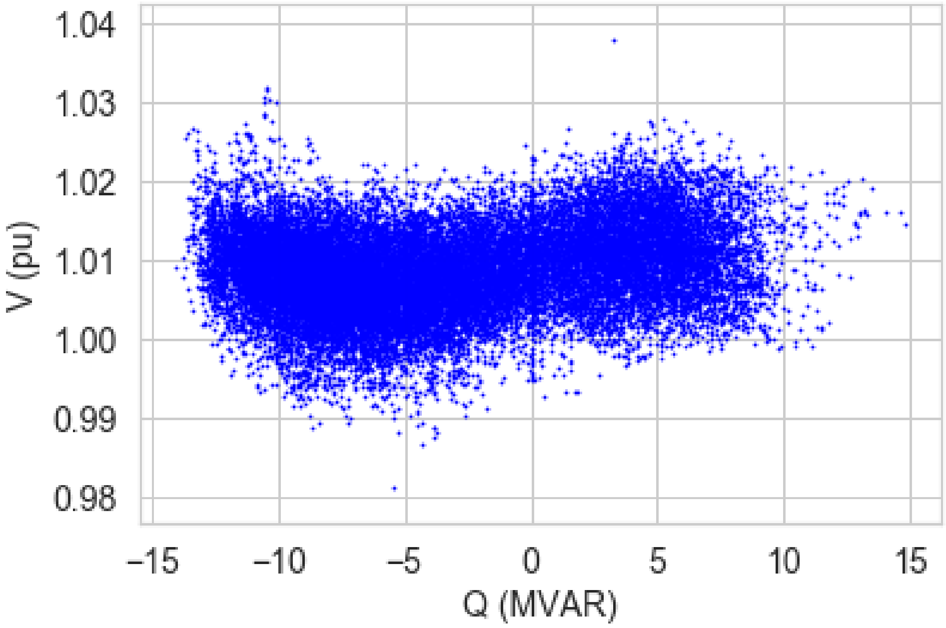
A.34 As noted above, the presence of a good sinusoidal voltage waveform is critical for grid-following inverters. Poor quality voltage waveform will cause the inverter to lose synchronism, potentially resulting in the inverter disconnecting from the network. Figure 15 shows the voltage waveforms at the Pakuranga, Bream Bay and Hororata GXPs under a simulated fault.

A.35 As expected, with high system strength the Pakuranga GXP can maintain good quality voltage waveform during normal operation, fault inception and the recovery period. The system strength at this GXP therefore supports reliable grid-following inverter operation. This contrasts with the Bream Bay and Hororata GXPs, which exhibit a highly distorted voltage waveform during fault inception and the recovery period.

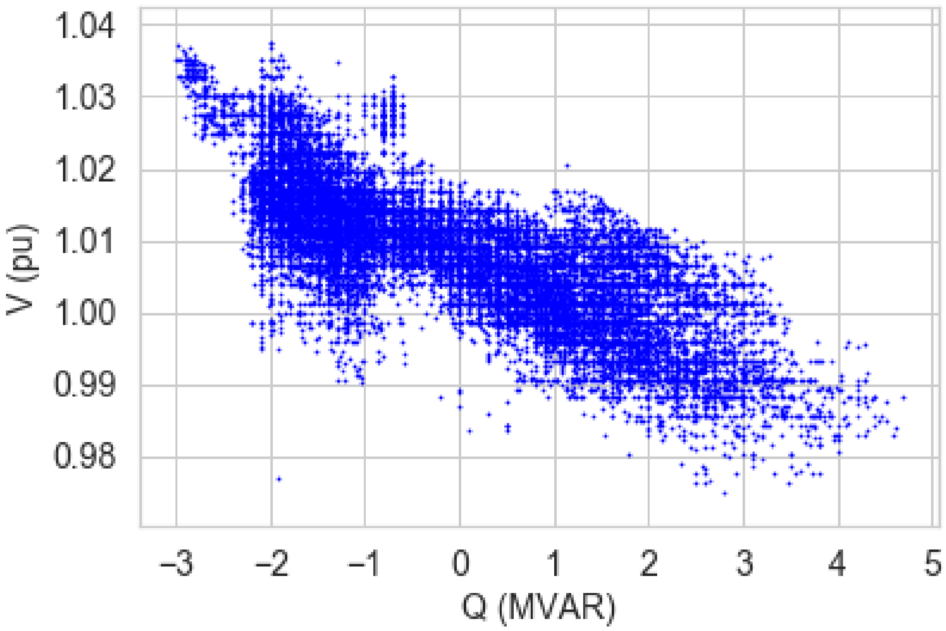
A.36 It is important to have good voltage waveform during fault inception and recovery, to allow the inverter control system to track the voltage on the network and the phase angle. This is necessary to support the power system to ride through the fault.

Figure 14: Voltage deviations at Pakuranga and Hororata GXPs

Voltage and reactive power at the Pakuranga GXP (Bus: PAK_220 kV_AV)



Voltage and reactive power at the Hororata GXP (Bus: HOR_66 kV_AV)

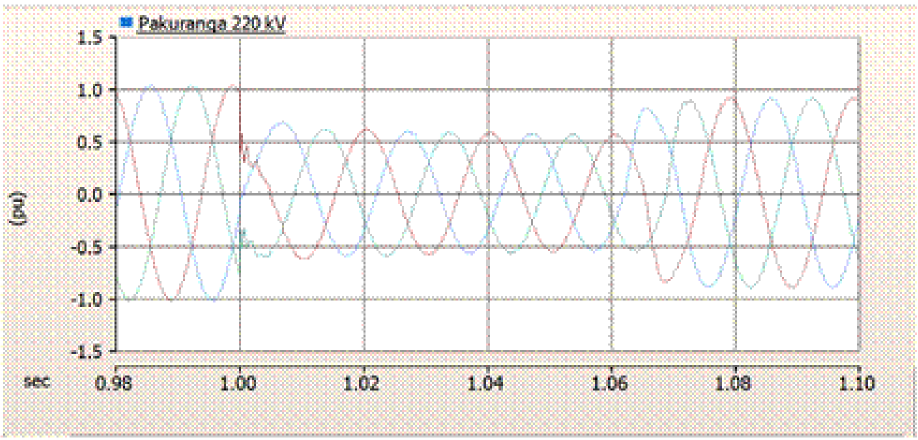


Source: System operator

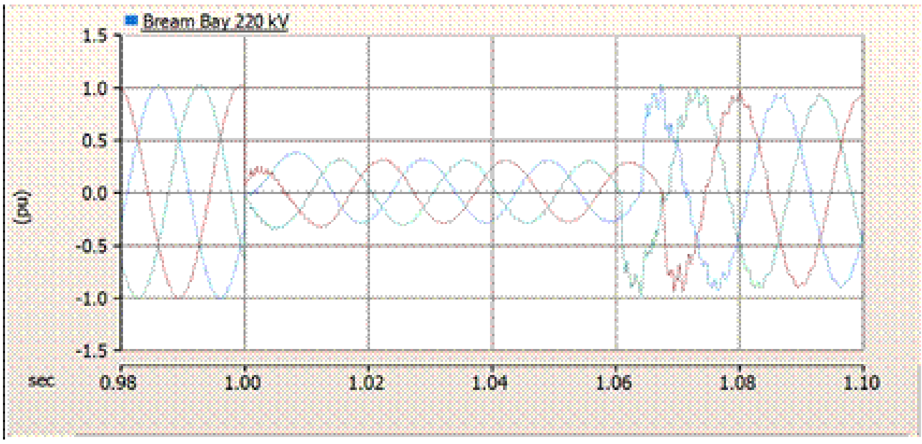
Notes: 1. The negative values on the horizontal axis represent reactive power flows from the distribution network to the transmission network.

Figure 15: Voltage waveform at Pakuranga, Bream Bay and Hororata GXPs

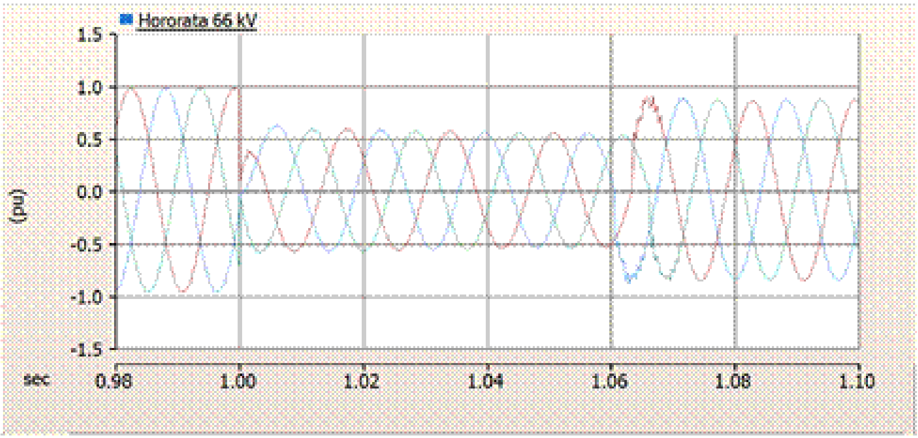
Voltage waveform at the Pakuranga GXP is reflective of a high system strength GXP



Voltage waveform at the Bream Bay GXP is reflective of a low system strength GXP



Voltage waveform at the Hororata GXP is reflective of a low system strength GXP



Source: System operator

Notes:

1. A 10 ohm three phase fault has been applied for three cycles (60 milliseconds) at each bus. The bus voltages are then observed.
2. Fault level at Pakuranga 220 kV: 16.1 kA; Fault level at Bream Bay 220 kV: 5.2 kA; Fault level at Hororata 66 kV: 4.5 kA.
3. The fault level data is from Transpower's 2021 transmission planning report.

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Appendix B Format for submissions

Question		Comment
Q1.	Do you agree with the description of the first common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q2.	Do you agree with the description of the second common quality issue (ie, first voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q3.	Do you agree with the description of the third common quality issue (ie, second voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q4.	Do you agree with the description of the fourth common quality issue (ie, third voltage-related issue) and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q5.	Do you agree with the description of the fifth common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q6.	If you are a distributor, what is your experience of asset owners sharing information with you for network operation purposes?	
Q7.	Do you agree with the description of the sixth common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q8.	Do you agree with the description of the seventh common quality issue and that addressing it should be a high priority? If you disagree, please provide your reasons.	
Q9.	Do you consider there to be other high priority common quality issues not identified in this paper that are occurring or that you expect to occur because of:	
a.	the uptake of inverter-based resources, and/or	
b.	how the Code enables different technologies?	

Glossary of abbreviations and terms

AC	alternating current
AGC	automatic generation control
AOPO	asset owner performance obligation
AS/NZS	Australian standard / New Zealand standard
AUFLS	automatic under-frequency load shedding
Authority	Electricity Authority
BESS	battery energy storage system
Code	Electricity Industry Participation Code 2010
DC	direct current
DER	distributed energy resource
FKC	frequency keeping modulation control
FSR	Future Security and Resilience
GXP	grid exit point
HDF	harmonic distortion factor
Hz	hertz
HVDC	high voltage direct current
ICP	installation control point
IEC	International Electrotechnical Commission
IEC TS	International Electrotechnical Commission technical specification
IEEE	Institute of Electrical and Electronics Engineers
kVAr	kiloVolt-Amps reactive
kW	kilowatt(s)
MBIE	Ministry of Business, Innovation and Employment
MDAG	Market Development Advisory Group
MFK	multiple provider frequency keeping
MW	megawatt(s)
NZECP	New Zealand Electrical Code of Practice
PPO	principal performance obligation
PV	photovoltaic
RMS	root mean square
ROCOF	rate of change of frequency
SCADA	supervisory control and data acquisition
SFK	single provider frequency keeping
SSSC	static synchronous series compensators
STATCOM	static synchronous compensator
SVC	static volt-amps reactive compensator
THD	total harmonic distortion
VAR	Volt-Amps reactive