Meeting date: 6 July 2023

ELECTRICITY AUTHORITY
TE MANA HIKO

CQTG Briefing - meeting number 1

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1. Introduction

1.1. The review of the common quality obligations in Part 8 of the Electricity Industry Participant Code 2010 (Code) is the highest priority item on the Authority's Future Security & Resilience (FSR) roadmap.

1.2. On 4 April 2023, the Authority released an issues paper seeking feedback from interested parties on:

(a) whether we had correctly described the key issues with the common quality requirements in Part 8 of the Code

(b) that addressing each of these issues should be a high priority

(c) whether there are any other high priority common quality issues we had not identified.

1.3. The deadline for submissions was 30th May 2023. We received 23 submissions, all of which have been published on our website.

1.4. The issues paper is the first of several key milestones for this project:

(a) **April 2023 –** Issues Paper released (completed)

(b) **June 2024 –** publish Options Paper

(c) **March 2025 –** publish Decision Paper and Proposed Code Changes Paper

(d) **August 2025 –** publish final Code changes.

1.5. Due to the complex nature of Part 8, the Authority has created the Common Quality Technical Group (CQTG) specifically to provide expert technical advice to the Authority as part of this review.

2. Objectives of first CQTG meeting

2.1. The primary objectives of the first CQTG meeting are to:

(a) confirm that all key issues with the common quality requirements in Part 8 of the Code have been identified

(b) consider a long list of options to address these key issues prepared by the Authority, and confirm any additional plausible options

(c) agree a shorter list of options to address these key issues, as an interim step towards a short list of options that will be prepared for consideration at the next CQTG meeting

(d) agree some 'no-regrets' system studies the Authority can request the system operator to scope, with the scope(s) considered at the next CQTG meeting.

3. Meeting agenda

Time	Item
Prior to 9:00 am	**Sign in at reception**
9:00 am	**Welcome and introductions (15 mins)**
9:15 am	**Overview of the FSR work programme and the CQTG's role (20 mins)**
9:35 am	**Additional common quality issues identified through consultation (35 mins)** • Objective: Confirm that all key issues with the common quality requirements in Part 8 of the Code have been identified
10:10 am	**Criteria for evaluating options to address issues (20 mins)**
10:30 am	**Morning tea (15 minutes)**
10:45 am	**Long list of options (60 mins)** • Objective: Consider a long list of options to address the key Part 8 common quality issues, and confirm any additional plausible options
11:45 am	**Shorter long list of options (35 mins)** • Seeking agreement on options removed from the long list based on the criteria #1
12:20 pm	**Lunch (45 minutes)**
1:05 pm	**Medium list of options (90 mins)** • Objective: Agree a shorter list of options to address these key issues, as an interim step towards a short list of options
2:35 pm	**No regrets system studies (20 mins)** • Objective: Agree some 'no-regrets' system studies the Authority can request the system operator to scope
2:55pm	**Next meeting (5 mins)**
3:00 pm	**End of meeting**

4. Common quality issues raised in submissions

4.1. In the Part 8 common quality issues paper, the Authority sought feedback as to whether:

(a) we had correctly described the issues with the current common quality requirements in Part 8 of the Code

(b) submitters considered there were other high priority common quality issues that we had not identified.

4.2. The table below summarises the common quality issues raised by submitters. The Authority considers almost all these issues can be categorised within the seven issues set out in the issues paper.

4.3. **Common quality issues raised by submitters**

	Submitter	Summary of the issue
	Issue 1 • **Inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia**	
1.	Electricity Engineers' Association of NZ Transpower	The action to zero the time error once a day is not needed for the power system to function i.e., there is no consequence for frequency or voltage management if zeroing the time error doesn't occur.
2.	ElectroNet	The Code should be more explicit on the technical requirements for BESS, especially when they are charging and operating as a load. Do they have frequency support obligations in this scenario, and if so, how do these differ from when they are exporting and operating as a generator?
3.	Contact Energy ElectroNet Mercury Energy	The South Island 45 Hz for 30 seconds under-frequency ride through requirement for South Island generators is outside of equipment supplier norms and has potentially discouraged some South Island generation development, due to limiting the available equipment and the ability to maintain competitive tension from suppliers.
4.	Mercury Energy	Request for the Authority and system operator to be involved in influencing standards for small-scale generation.
5.	Meridian Energy	The minimum requirements for testing and coordinating grid interface protection set out in schedule 8.3, Technical Code A, Appendix A are ambiguous. In practice there is a range of interpretations across the sector. The period of testing may be uneconomic given modern self-testing technology.
6.	Transpower	The system operator dispensation process should be reviewed as to whether its current form is fit for purpose for all new assets connecting to the grid and operating in the system. If continued, the current process may impose unnecessary costs on the grid owner and consumers.
	Issues 2, 3, 4 • **Inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows**	

	• **Inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system** • **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**	
7.	Electricity Engineers' Association of NZ	Investigate how inverter-based resources could provide voltage regulation when not producing active power.
8.	Electricity Engineers' Association of NZ	Consider reviewing the voltage standard, including AS/NZS 4777.2:2020, or alternatives.
9.	ElectroNet	The industry would benefit from clearer guidance on how the connection point is determined. Clarity on the connection point would also enable additional clarity on other compliance issues such as reactive power capability and power quality.
10.	ElectroNet	The Code should be more explicit on the technical requirements for battery energy storage systems, especially when they are charging and operating as a load. Do they have voltage support obligations in this scenario, and if so, how do these differ from when they are exporting and operating as a generator?
11.	ElectroNet	In the fault ride through clause (8.25B), the Code is not explicit about the trade-off between reactive and active power during a fault.
12.	ElectroNet	The Code should anticipate an increasing need for electro-magnetic transient (EMT) analysis to prove the control system and power electronic behaviour, including direct current transients is properly accounted for in the modelling to prove the compliance of inverter-based resources with technical codes. This becomes especially important when the point of connection is "weak". Currently there is a lack of clarify on the extent of studies required.
13.	Elliston Power Consultants	With more solar penetration in New Zealand, voltage rise problems on suburban feeders will occur. This is the key issue for the FSR review of common quality requirements on 'voltage'. A distributor is not recompensed for the service it provides to any premises with a generation system operating at unity power factor, since residential consumers are only billed for active power, not VARs/reactive power. The reduction in efficiency is due a network designed and priced to provide premises with the regulated 0.95 power factor now providing power at a much worse power factor. The implications of this need to be investigated urgently, prior to even a modest penetration of distributed generation.
14.	Mercury Energy	Request for the Authority and system operator to be involved in influencing standards for small-scale generation.
15.	Meridian Energy	The minimum requirements for testing and coordinating grid interface protection set out in schedule 8.3, Technical Code A, Appendix A are ambiguous. In practice there is a range of interpretations across the sector. The period of testing may be uneconomic given modern self-testing technology.
16.	Northpower	In relation to an increased likelihood of network performance issues due to inverter-based resources disconnecting from the power system, there is also a safety issue for both the public, and electrical workers, due to the potential to cause the protection to mal-operate, as the protection is more likely to not operate for a fault.

17.	Northpower	A second point about the voltage/duration curves in Part 8, for distributors with large motor loads the voltage depression will be greater than that measured at the grid for a grid disturbance.
18.	Tesla Consultants	There is an issue in relation to asset capability under the simultaneous application of voltage and frequency obligations (clauses 8.19 & 8.23). Synchronous machines have problems with continuous or short time overfluxing capabilities.
19.	Tesla Consultants	Co-ordination of Power System Stabiliser (PSS) Settings. It's left up to the connecting party with little/no guidance from the system operator. This approach is loose compared with the more hands-on approach in Australia.
20.	Tesla Consultants	There is ambiguity around Part 8 protection requirements. 220 kV is very specific, 110 kV not so, especially busbar protection. Lots of renewables will seek to connect at 110 kV.
21.	Transpower	The system operator dispensation process should be reviewed as to whether its current form is fit for purpose for all new assets connecting to the grid and operating in the system. If continued, the current process may impose unnecessary costs on the grid owner and consumers.
22.	WEL Networks	Other issues may become evident with increasing amounts of inverter-based generation (eg, increase in voltage unbalance and rapid voltage changes arising from rapid changes in output at PV solar installations). It is not certain as to the extent or timing of any such problem.
	Issue 5 • There is some ambiguity around the applicability of harmonics standards	
23.	Mercury	Request for the Authority and system operator to be involved in influencing standards for small-scale generation
24.	Northpower	EV charging is a non-linear load and will produce harmonics whether the EV charger is on-board the EV (mode 2 & 3 AC charging) or external (mode 4 DC charging).
25.	Transpower	The most urgent matter is to have an appropriate harmonic standard and updated methodology for allocating harmonics. Also, the voltage flicker standard in the connection code within the benchmark agreement should be addressed and amended as part of this review.
	Issue 6 • Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner	
26.	Electricity Engineers' Association of NZ Transpower	The Authority should consider the impact of embedded generation on the ability to restart/re-energise GXPs. A lack of information in Part 8 of the Code on roles and responsibilities for provision and co-ordination of systems such as anti-islanding is contributing to auto-reclose being disabled in the presence of embedded generation. Without auto-reclose there is a prolonged loss of supply.1
27.	Northpower	The issue for distributors is not so much knowing where the distributed generators are, or their size and type of energy source, but rather the operational status and if any alterations have been made.

[1] The Authority considers this is within the scope of Issue 6 because the system operator and distributor each need information on islanded networks as part of re-energising a distribution network (eg, which feeder is to be switched on and when?).

28.	Northpower	Equipment has a lifecycle and therefore equipment will be changed over time.
29.	Northpower	Inverter settings are programmable and can be changed, which could change the performance of the distributed generation system. Potentially this issue could apply to larger generation schemes as well.
30.	Transpower	Network configurations such as backfeeds and parallels will need more thought if embedded inverter-based generation is significant. Improved information sharing between the system operator and distributors will be needed.
31.	Vector	Concerned about the issue of "tier bypass", where the operator of one tier of the power system is dispatching resources connected to another tier of the power system, without any visibility of the real-time constraints on those networks that comprise the other tier. The system operator does not have visibility beyond the GXP and will not have knowledge of all the local physical and power quality constraints impacting dispatchable DER
	Issue 7 • The Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies	
32.	Electricity Engineers' Association of NZ	The Authority should consider expanding the "common quality" definition to distribution networks.
33.	Electricity Engineers' Association of NZ Transpower	The Authority needs to consider ensuring any changes made to Part 8 are aligned in Part 12. Part 8 of the Code ties to the Connection Code under Part 12 and common quality considerations include harmonics (as identified), power factor (a lot of leading power factor (capacitive) is coming into the grid), and flicker due to electrification of load (transport and industry).
34.	ElectroNet	To anticipate potential changes in technology, and to avoid regrets, it should be easier to alter technical requirements and aspects of the Code and a more transparent process should be followed.
35.	Northpower	The Code should state more clearly that it applies to network connected batteries.
	Other issues	
36.	Electricity Engineers' Association of NZ	Has the Authority considered how new generators may potentially impact commercially on other generators and / or grid operation? This has become an issue in other jurisdictions (i.e., the UK and Australia).
37.	Electricity Engineers' Association of NZ	Higher penetration of inverter-based generation resources is driving protection manufacturers to amend protection algorithms to improve discriminative protection. However, inverter-based resources can also improve control settings.

5. Options identified in submissions

5.1. Some submissions included options to address the key issues with the common quality requirements in Part 8 of the Code.

5.2. The table below contains those options the Authority has identified in submissions.

5.3. **Options identified in submissions**

	Submitter	Summary of the issue
	Issue 1 • **Inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia**	
1.	Contact Energy	Perhaps there is an option to put in place an intermediary step which has a subset of the Part 8 requirements for connections lower than 30MW and larger than a practical minimum MW value.
2.	Contact Energy	Consider increasing the current MFK bands if there are concerns around maintaining frequency within the normal band in the future.
3.	Contact Energy ElectroNet	Review clause 8.19(3) of the Code and increase the under-frequency ride through level in the South Island to a more pragmatic level / to be in line with the North Island level.
4.	Elliston Power Consultants	Frequency limits should be reviewed. Eg, modern power supplies for a myriad of household appliances and industrial equipment in use today are able to operate at much wider frequency tolerances, such as “50 Hz to 60 Hz”, instead of being “within 1.5% of 50 Hz”. Investigate whether the historical “normal band” is fit for purpose in the future. A transition pathway looking forward can be initiated, to ensure that 20 or 30 years from now, with much more advanced technologies, we are not constrained by power quality standards that were set decades and perhaps even a century ago, to suit equipment that has long since become obsolete, decommissioned, and removed from the grid.
5.	Elliston Power Consultants	The FSR work programme should not be distracted by trying to address generator behaviour in relation to dead bands but instead look to the future structure of the power system and identify procurement mechanisms for instantaneous reserves in that context.
6.	Manawa Energy	We encourage the Authority to consider grandfathering arrangements for existing generation assets, where appropriate.
7.	Meridian Energy	We recommend consideration is given to a wide range of possible options to ensure that system support is available when needed, including designing new and expanded ancillary services to procure system support services. It may be lower cost to invest in additional capability from existing synchronous generation, rather than impose costs on all inverter-based resources. New and expanded ancillary services could also reward existing system support services like governor response and inertia that are currently provided for free and are only going to become more important.

		Meridian generally believes market-based approaches will deliver better outcomes than rules-based approaches, hence our suggestion that the Authority should consider expanded ancillary services to reward governor response, which will become increasingly valuable. Decisions would also need to be made about how the costs to pay for the ancillary service are allocated to beneficiaries of frequency keeping through governor response.
8.	Meridian Energy	The Code provisions regarding speed governors should also be reconsidered so that operators of inverter-based resources do not have to apply for an equivalence arrangement in the absence of a speed governor.
9.	Transpower	A review of the system operator dispensation process could include ensuring it is future-proofed for possible advances in inverter technology that support higher quality system operation.
10.	WEL Networks	New ancillary services (e.g. inertia, regional fast intermittent generation firming) may be a good option for managing frequency deviations and reducing system inertia.
11.	WEL Networks	A market-based arrangement around fast frequency variations where payments are made to those who boost their output when frequency drops and costs are imposed on those who are dropping output at the time.
12.	WEL Networks	Review frequency related obligations (e.g. in the Electricity (Safety) Regulations 2010 and the system operator's principal performance obligations).
13.	William Harding	Shut down all forms of asynchronous generation, including all proposed large network-connected solar PV farms.
	Issues 2, 3, 4 • **Inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows** • **Inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system** • **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**	
14.	Centralines and Unison (combined)	Support standards-based solutions such as the Volt-Var control mode in AS/NZS 4777.2-2020 as a mitigation at the distribution level.
15.	Centralines and Unison (combined)	There should be consistent requirements for generators to understand and expect from all distributors.
16.	Centralines and Unison (combined)	There should be simple requirements for distributors, to ensure administrative and cost efficiencies.
17.	Contact Energy	Perhaps there is an option to put in place an intermediary step which has a subset of the Part 8 requirements for connections lower than 30MW and larger than a practical minimum MW value.

18.	Electricity Engineers' Association of NZ	The Authority should consider developing an interoperability policy and regulatory framework under which connections to a distribution network would be required to demonstrate that the inverter is interoperable with the distribution network's utility server and is capable of dynamic export limitation.
19.	Electricity Engineers' Association of NZ	Consider how to test generator fault ride through on a live system.
20.	ElectroNet	The Authority should consider implementing voltage support requirements that more carefully consider the nuances of the connection point voltage and capability of regional networks. The German grid code allows network operators to select between three different capability curves, depending on the needs of the network. This allows for a nuanced selection of appropriate plant capability based on system needs. A similar approach in NZ could have merit.
21.	ElectroNet	Consider different fault ride through curves for different technologies. This has been seen in the British grid code, where synchronous machines have more permissive fault ride through requirements than inverter-based resources.
22.	Elliston Power Consultants	Prior to making it easier to install larger inverter-based resources connected to distribution networks, the reactive power contribution from these systems needs to specified/prescribed, so that purchasers of such systems are aware of the impact that any such requirement will have on the nameplate rating of their distributed generation systems (contribution to VARs reduces the kW output available for offsetting power imports).
23.	King Country Energy	A national standard to specify minimum capability of inverters and have manufacturers publish relevant settings for their products to meet NZ standards.
24.	Manawa Energy	We encourage the Authority to consider grandfathering arrangements for existing generation assets, where appropriate.
25.	Mercury Energy	Supports a mechanism that enables the system operator to contract with plant owners to operate plant in synchronous condenser mode to address identified system strength and inertia shortfalls.
26.	Meridian Energy	Clarify what reactive support the system operator will require from participants. Meridian generally prioritises making peak capacity available.
27.	Meridian Energy	Clarify AVR droop limits, which appear to be a regulatory gap as it is not clear what level of droop is acceptable and the settings in turn influence how much voltage support is provided.
28.	Meridian Energy	Clarify requirements in respect of tap changer range. We have found that installing tap changers with large ranges into transformers is expensive and they are known to be a leading cause of equipment failure, but operational experience is that only a small range is ever used.
29.	Meridian Energy	Clarify fault ride through requirements. Clause 8.25B could be clarified so that generators recover in a way that is proportionate to the fault. Furthermore, the assumption that simultaneous application of 8,19 and 8.23 is not required could be clarified.
30.	Nova Energy	Equipment specification guidelines to accompany grid / network connection and operation standards would be a beneficial low-cost interim measure.

31.	SwitchDin	Have voltage standard of 230V±10%.
32.	SwitchDin	Develop interoperability standard for distributors and sites with inverter-based energy resources.
33.	SwitchDin	Mandate compliance with AS/NZS 4777.2:2020.
34.	Transpower	Transpower, as a grid owner, should have access to unencrypted equipment and control system models to understand how plant will interact with the grid and perform during grid events. Provision of static and dynamic models would ideally be provided to Transpower in both its roles (system operator and a grid owner).
35.	Transpower	A review of the system operator dispensation process could include ensuring it is future-proofed for possible advances in inverter technology that support higher quality system operation.
36.	Vector	Would welcome regulatory support for further implementation of dynamic operating envelopes.
37.	Vector	Supports the proposed expansion of the allowable voltage range to ±10% from ±6% of nominal voltage as this will lead to increased hosting capacity of distributed generation on distribution networks.
38.	Vector	Supports the Minimum Energy Performance Standards (administered by EECA) ensuring that all EV chargers sold or installed in NZ have smart capability and are set to off-peak charging by default.
39.	WEL Networks	Widening the voltage range in Part 8 certainly seems possible in parts of the grid.
40.	WEL Networks	A market arrangement for grid reactive power could be implemented. This can remove the need for voltage related AOPOs. For example, a wholesale market price signal could be provided at each node for reactive power. Those parties helping the voltage issues can be rewarded and those parties adding to the voltage issue can be allocated costs.
41.	WEL Networks	Many inverter-based energy storage systems are likely to increasingly have grid forming capabilities. Consider these systems' ability to provide islanded supply during interruptions or support during emergency conditions.
42.	WEL Networks	Develop a system strength ancillary service.
43.	WEL Networks	Review the voltage-related principal performance obligations and asset owner performance obligations
44.	WEL Networks	It may be appropriate to review whether a different set of fault ride through obligations should apply to smaller distributed energy resources (DERs).
45.	WEL Networks	System operator has a means of mitigating this issue through instantaneous reserves (i.e. the amount of inverter-based generation at risk of tripping for a fault becomes the contingent event).
46.	William Harding	Shut down all forms of asynchronous generation, including all proposed large network-connected solar PV farms.
	Issue 5 • There is some ambiguity around the applicability of harmonics standards	

47.	Contact Energy	Harmonic distortion allocations should be on a case by case basis.
48.	Electricity Engineers' Association of NZ	Absolute harmonic standards (eg, NZ ECP36) should not be mixed with statistical standards (eg, IEC and AS/NZS standards) as this can cause issues in interpretation and practice. If after review, it is agreed that absolute limits for a system are to be used, as in NZECP36, then appropriate installation and device level limits and allocation methods need to be developed that are consistent with this methodology. This has not currently been done.
49.	Vector	Recommends the Authority take a proportional response with respect to harmonics. Recommends monitoring local and international trends, particularly in areas like South Australia where distributed generation penetration rates are the highest in the world, so that we can gather data and better understand how actions undertaken to decarbonise the economy are specifically related to harmonics issues.
50.	William Harding	Install harmonic filters on all smart meters.
	Issue 6 • Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner	
51.	Centralines and Unison (combined)	Develop solutions to standardise and streamline the availability of fault and status information including from small scale distributed generation.
52.	Electricity Engineers' Association of NZ	Consider establishing a central distributed energy resources (DER) register (like the AEMO one for Australia), based on information provided by distributors, but which relies on standardised reporting processes including mandated input by installers during the connection process. The DER register should include electric vehicle (EV) chargers.
53.	ElectroNet	Information requirements should be appropriate to the stage of a project and to the size of a project. Information requirements should recognise natural differences in capabilities of different technologies. Modelling and information requirements should be software platform agnostic, if possible. There should be greater clarity on what software models are required and for what aspects of the Code they should be used for to demonstrate compliance.
54.	Elliston Power Consultants	Items that enable the proper functioning of the power system need to be identified, with clear articulation of the rationale for the required information. The information may include real time information where this affects system operations.
55.	King Country Energy	Populate the ICP registry with relevant generation data.
56.	Meridian Energy	Regarding the issue of proprietary asset-related information, one potential option could be to consider the Australian model where equipment manufacturers are required to share information directly with the system operator under a non-disclosure agreement.

57.	Major Electricity Users' Group	Look at how demand side response can be robustly incorporated into the system, where it is beneficial for both the system and the demand participant.
58.	Neil Walbran Consulting	If demand-side flexibility resources' offer information were to differentiate between inverter and non-inverter demand-side flexibility resources, then this offer information could be used to understand the quantity of inverter based embedded resource present in real time. This approach may not prove to be practical but there may still be merit in coordinating the FSR workstream and the MDAG pricing under 100% renewables workstream.
59.	Nova Energy	Current regulations appear to provide adequate mechanisms for Transpower and distributors to resolve this issue.
60.	SwitchDin	Establish a register of distributed energy resources.
61.	SwitchDin	Enable customer access to local, real time metering data.
62.	Transpower	The Code could support that provision of asset capability statement (ACS) information to the system operator can be shared with Transpower, as a gird owner, to avoid duplication of effort by the transmission customer and remove the risk of information differences.
63.	Transpower	The level of penetration of embedded generation (and type) at each GXP and GIP should be available to Transpower both for real-time system operation needs and for grid planning and system analysis.
64.	Transpower	Transpower, as a grid owner, preferably needs access to unencrypted equipment and control system models to understand how plant will interact with the grid and perform during grid events. Since models are proprietary to equipment manufacturers, contractual controls would need to be in place to ensure commercial confidentiality.
65.	Vector	Modify distributors' network connection standards to request consumers or their agents to notify distributors of any EV chargers connected to the distribution network.
66.	Vector	Distributors offer tariffs to provide asset owners with an incentive to provide information about distributed energy resources (eg, distributed energy resources are managed by the distributor or retailer or a DER manager for network operation purposes).
67.	WEL Networks	The establishment of a commercial model is required for ongoing provision of operational information.
68.	WEL Networks	Better forecasting of aggregate intended output of distributed energy resources (e.g. PV solar, wind, EV charging, demand response, etc) at the GXP level would be useful to the system operator. These forecasts can be provided by the distribution network operator.
69.	WEL Networks	Alternative methods of modelling the composite dynamic frequency and voltage response at the GXP level rather than requiring massive numbers of DER owners to provide asset capability information to the system operator and distributor should be investigated.
	Issue 7 • The Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies	

70.	Electricity Engineers' Association of NZ	The Authority should consider expanding the "common quality" definition to distribution networks.
71.	Electricity Engineers' Association of NZ Transpower	The Authority needs to consider ensuring any changes made to Part 8 are aligned in Part 12. Part 8 of the Code ties to the Connection Code under Part 12 and common quality considerations include harmonics (as identified), power factor (a lot of leading power factor (capacitive) is coming into the grid), and flicker due to electrification of load (transport and industry).
72.	ElectroNet	The Code could require that the system operator establish model guidelines and model information requirements documents, leaving the technical details to the system operator rather than these being specified directly in the Code.
73.	Mercury Energy	Write performance requirements so they are applicable across technology groups.
74.	Northpower	Suggest in some cases using generic terms such 'reactive power compensation equipment' (e.g. SVC, STATCOM, SSSC, etc), rather than stating just one type of reactive power equipment.
75.	William Harding	Revoke the Electricity Industry Participation Code 2010.

6. Draft long list of options

6.1. The Authority has prepared a draft long list of options to address the key issues with the common quality requirements in Part 8 of the Code.

6.2. This long list incorporates a number of options contained in submissions on the issues paper.

6.3. The Authority seeks the CQTG's feedback on this draft long list. In particular, we seek the CQTG's views on whether there are any additional plausible options that should be included in the list.

6.4. **Long list of options**

Option number	Description
	Issue 1 • Inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia
1.	Lower the 30 MW threshold for generating stations to be excluded by default from complying with the frequency regulation capability asset owner performance obligation (AOPO)
2.	Resources (e.g. generators, batteries) must make available X% of maximum rated capacity to support frequency in underfrequency events
3.	New market product – 1 second reserve / synthetic inertia
4.	Widen the normal band
5.	Set a permitted dead band beyond which a generation station must contribute to frequency keeping and instantaneous reserve
6.	Procure more frequency keeping through widening the frequency keeping band
7.	Lower the minimum frequency keeping threshold below 4 MW and have a national market for frequency keeping
8.	Have a new ancillary service for inertia
9.	Allocate frequency keeping costs to the causers of frequency deviations
10.	Put in place ramping limits on generation plant for post-disturbance or change-of-MW output (eg, due to wind gust or cloud covering)
11.	Require / incentivise improved forecasting by generators. (Refer to MDAG's options paper for price discovery in a renewables-based electricity system, and the Authority's issues and options paper on a review of forecasting provisions for intermittent generators in the spot market.)
12.	Review the dispensations and equivalence arrangements framework
	Issues 2, 3, 4

	• Inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows • Inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system • 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
13.	Assign voltage support obligations to distributed energy resources (eg, by revising the 'point of connection' definition)
14.	Revise the GXP power factors specified in the Connection Code, to manage the import and export of reactive power at a GXP
15.	Widen the voltage ranges for which distribution-connected assets must be capable of being operated
16.	Lower the 30MW threshold for generating stations to be excluded by default from complying with the fault ride through obligations in the Code
17.	Revise or remove the fault ride through envelope specified in Part 8 of the Code
18.	Establish a new ancillary service for reactive power management
19.	Impose greater obligations on distributors and the system operator to maintain certain voltage ranges / system strength at GXP/GIPs
20.	Establish a new system strength ancillary service
21.	Require alignment of voltage-related connection standards across distribution networks
22.	Review the dispensations and equivalence arrangements framework
	Issue 5 • There is some ambiguity around the applicability of harmonics standards
23.	Locate the standard(s) for harmonics in one piece of legislation / regulation (eg, the Electricity Industry (Safety) Regulations 2010 or the Code)
24.	Asset owners (grid-connected parties, grid owners, and embedded generators) are made responsible for managing the harmonics caused by their asset(s)
25.	Make the system operator responsible for managing harmonics on the transmission network (eg, a new PPO) and distribution network operators responsible for managing harmonics on distribution networks, with costs recovered from the causers of the harmonics
26.	Remove the first-mover advantage associated with total harmonic distortion (THD) by requiring the first mover to give up some of their share of THD
	Issue 6 • Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and

	operation of the power system in a safe, reliable, and economically efficient manner
27.	Lower the deminimis for generating stations to provide real time operational data to the system operator, and require the same information to be provided to distribution network operators in relation to embedded generating stations
28.	Require asset owners (grid-connected parties, grid owners, and embedded generators) to provide asset capability information required for network operators to meet their regulatory obligations
29.	Require wind generation to undertake periodic testing and provide results to system operator and distribution network operators so they can keep their models up to date
30.	Where a flexibility provider is providing a service to an asset owner, leave it to the flexibility provider rather than the asset owner to provide the network operator with the information required by the network operator to use the flexibility service
31.	Require asset owners to provide system operator with sufficiently detailed information so that there is no "black box" when the system operator comes to use the information for equipment performance assessment and checking compliance with the Part 8 technical requirements
32.	Establish a registry of distributed energy resources
	Issue 7 • The Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies
33.	New / amended / obsolete definitions are identified and addressed as part of the work on the above 6 issues

7. An initial assessment of the long list of options

7.1. The Authority is cognisant that the CQTG has limited availability / time to evaluate each of the options in the draft long list contained in the table above, plus any additional options identified by the CQTG at its 6 July 2023 meeting.

7.2. Therefore, the Authority has undertaken an initial assessment of the draft long list of options against the following criterion:

- *The option is feasible / implementable with little or no risk of unintended consequences.*

7.3. This criterion is the first of 7 criteria the Authority has developed to evaluate options to address the identified issues with the common quality requirements in Part 8 of the Code. (please refer to **Appendix A – Evaluation Criteria**).

7.4. The Authority has removed from the draft long list those options the Authority considers feasible but:

(a) expensive <u>or</u> which have a long implementation <u>and/or</u> a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)

(b) expensive <u>and</u> which have a long implementation <u>and/or</u> a significant risk of unintended consequences (>5 years to change the Code, >7 years to change assets, >$100m implementation cost).

7.5. The Authority has retained in the draft long list those options the Authority considers:

(a) strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)

(b) moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)

(c) feasible with uncertain risk of unintended consequences.

7.6. The reason for this approach is to enable options that can deliver 'quick wins' to be progressed ahead of options that require a longer gestation, and which are not necessarily needed within the next five years.

7.7. The Authority is not proposing to discard the options removed from the long list, but rather to defer their further consideration for the time being. Our current thinking is to return to them within the next 12-24 months.

7.8. The tables below contain the options remaining in / removed from the draft long list after this initial assessment.

7.9. The Authority seeks the CQTG's feedback on this initial assessment. We are also open to feedback on our approach to this assessment – ie, favouring options that deliver quick (or at least quicker) wins.

7.10. We propose to do the same assessment, amended as necessary to factor in CQTG feedback, for any options added to the draft long list at the CQTG's 6 July 2023 meeting.

7.11. Options remaining in the long list following an initial assessment

	Option description	Reason for retaining in long list
	Issue 1 • **Inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia**	
1.	Lower the 30MW threshold for generating stations to be excluded by default from complying with the frequency regulation capability asset owner performance obligation (AOPO)	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
2.	Set a permitted dead band beyond which a generation station must contribute to frequency keeping and instantaneous reserve	Feasible with uncertain risk of unintended consequences
3.	Procure more frequency keeping through widening the frequency keeping band	Strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)
4.	Lower the minimum frequency keeping threshold below 4 MW and have a national market for frequency keeping	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
5.	Allocate frequency keeping costs to the causers of frequency deviations	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
6.	Put in place ramping limits on generation plant for post-disturbance or change-of-MW output (eg, due to wind gust or cloud covering)	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
7.	Review the dispensations and equivalence arrangements framework	Feasible with uncertain risk of unintended consequences
	Issues 2, 3, 4 • **Inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows** • **Inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system** • **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**	
8.	Assign voltage support obligations to distributed energy resources (eg, by revising the 'point of connection' definition)	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)

9.	Revise the GXP power factors specified in the Connection Code, to manage the import and export of reactive power at a GXP	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
10.	Lower the 30MW threshold for generating stations to be excluded by default from complying with the fault ride through obligations in the Code	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
11.	Require alignment of voltage-related connection standards across distribution networks	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
12.	Review the dispensations and equivalence arrangements framework	Feasible with uncertain risk of unintended consequences
	Issue 5 • There is some ambiguity around the applicability of harmonics standards	
13.	Locate the standard(s) for harmonics in one piece of legislation / regulation (eg, the Electricity Industry (Safety) Regulations 2010 or the Code)	Strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)
14.	Asset owners (grid-connected parties, grid owners, and embedded generators) are made responsible for managing the harmonics caused by their asset(s)	Strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)
15.	Remove the first-mover advantage associated with total harmonic distortion (THD) by requiring the first mover to give up some of their share of THD	The Authority understands that Transpower, as a grid owner, is looking at this matter. The Authority is unaware of what, if any, work is being done by distributors on this matter.
	Issue 6 • Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner	
16.	Lower the deminimis for generating stations to provide real time operational data to the system operator, and require the same information to be provided to distribution network operators in relation to embedded generating stations	Feasible with uncertain risk of unintended consequences
17.	Require asset owners (grid-connected parties, grid owners, and embedded generators) to provide asset capability information required for network operators to meet their regulatory obligations	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)

18.	Require wind generation to undertake periodic testing and provide results to system operator and distribution network operators so they can keep their models up to date	Strongly feasible with no risk of unintended consequences (<1 year to change the Code, <2 years to change assets, <$10m implementation cost)
19.	Where a flexibility provider is providing a service to an asset owner, leave it to the flexibility provider rather than the asset owner to provide the network operator with the information required by the network operator to use the flexibility service	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)
20.	Require asset owners to provide system operator with sufficiently detailed information so that there is no "black box" when the system operator comes to use the information for equipment performance assessment and checking compliance with the Part 8 technical requirements	Feasible with uncertain risk of unintended consequences
	Issue 7 • The Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies	
21.	New / amended / obsolete definitions are identified and addressed as part of the work on the above 6 issues	Moderately feasible with low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation cost)

7.12. Options removed from the long list following an initial assessment

	Option description	Reason for removal from long list
	Issue 1 • **Inverter-based variable and intermittent resources cause more frequency fluctuations, which are likely to be exacerbated over time by decreasing system inertia**	
1.	Resources (e.g. generators, batteries) must make available X% of maximum rated capacity to support frequency in underfrequency events	Expensive <u>or</u> has a long implementation <u>and/or</u> a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost) The unintended consequence is that the cost of wholesale electricity would increase, which could exceed the benefit from reducing instantaneous reserves costs
2.	New market product – 1 second reserve / synthetic inertia	Expensive <u>or</u> has a long implementation <u>and/or</u> a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)

3.	Widen normal band	Expensive and has a long implementation and/or a moderate risk of unintended consequences (>5 years to change the Code, >7 years to change assets, >$100m implementation cost) The risk of unintended consequences is the key issue here – in relation to the operational effect on some generation and frequency-sensitive loads
4.	Have a new ancillary service for inertia	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)
5.	Require / incentivise improved forecasting by generators	Out of scope Part of the Authority's review of forecasting provisions for intermittent generators in the spot market
	Issues 2, 3, 4 • **Inverter-based variable and intermittent resources cause greater voltage deviations, which are exacerbated by changing patterns of reactive power flows** • **Inverter-based variable and intermittent resources can increase the likelihood of network performance issues due to inverter-based resources disconnecting from the power system** • **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**	
6.	Widen the voltage ranges for which distribution-connected assets must be capable of being operated	Out of scope Part of MBIE's review of the voltage limits for load connected to the low voltage network
7.	Revise or remove the fault ride through envelope specified in Part 8 of the Code	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)
8.	Establish a new ancillary service for reactive power management	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)
9.	Impose greater obligations on distributors and the system operator to maintain certain voltage ranges / system strength at GXP/GIPs	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)

10.	Establish a new system strength ancillary service	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)
	Issue 5 • There is some ambiguity around the applicability of harmonics standards	
11.	Make the system operator responsible for managing harmonics on the transmission network (eg, a new PPO) and distribution network operators responsible for managing harmonics on distribution networks, with costs recovered from the causers of the harmonics	Expensive or has a long implementation and/or a moderate risk of unintended consequences (>3 years to change the Code, >5 years to change assets, >$50m implementation cost)
	Issue 6 • Network operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable, and economically efficient manner	
12.	Establish a registry of distributed energy resources	Out of scope Part of the Authority's review of regulatory settings for distribution networks
	Issue 7 • The Code is missing some terms that would help enable technologies, and contains some terms that appear to not be fit for the purpose of appropriately enabling technologies	
13.	Not applicable	Not applicable