Options to help address the voltage common quality-related issues – Next steps

Common Quality Technical Group meeting – 17 October 2024

Contents

1. Purpose

1.1. The purpose of this paper is to summarise the key points from submissions on the consultation to address options for the voltage issues and suggested next steps, including refinements to existing options or additional options that should be considered.

1.2. The paper contains questions which we would like to discuss with the CQTG and get feedback on various points raised by submitters.

2. Overview

2.1. 16 submitters commented on the voltage paper:

Generator/Retailer	Generator	Lines company	Other
Genesis Energy	Lodestone Energy	Northpower	Electricity Engineers' Association
Mercury Energy	Manawa Energy	Orion	Independent Electricity Generators Association (IEGA)
Aurora Energy	NewPower	Powerco	
Meridian Energy	Pioneer Energy	Transpower	
Vector		WEL Networks	

3. Key points from submissions

General feedback

Prioritising the options

3.1. EEA agrees that voltage is important, but frequency is more important to address first.

3.2. EEA consider a combination of all 3 voltage options are needed, but the Authority should prioritise option 1 (to address issues 2 and 3).

3.3. Transpower's view is to prioritise extending voltage obligations and enable power factor management at the GXP (options 1 and 2) to ensure the most efficient provision of voltage management costs, and efficient use of the power system.

Alternative options not identified or considered

3.4. In addition to the options identified, several options were identified by submitters:

(a) **Genesis** advocates for reactive power export requirements to reduce linearly to zero, as the voltage at the point of connection increases from 1.05 to 1.1. This is especially applicable to new generation connecting to the distribution network, as they are unlikely to have a single transformer with an online tap changer.

(b) **Mercury** suggested the Authority consider the role of increasing amounts of DER installed at the consumer level. The Authority needs to ensure that appropriate standards (eg, AS 4777) are developed with settings appropriate for the New Zealand power system for solar, battery and EV charging systems.

(c) Both **New Power** and **IEGA** points out that the consultation paper does not consider grid forming (GFM) technologies. They note that this technology can solve multiple issues facing New Zealand's grid such as inertia, short circuit level, fault ride through and harmonics, and therefore should be evaluated in more depth. New Power recognise that that this technology has drawbacks around fault ride through, and other areas not directly relevant to voltage.

New Power also noted that in a 2023 report, Transpower recommended that all IBR over 1MW should be GFM. This recommendation was based on an in-depth study of fault ride through performance of GFM and grid following (GFL) technologies. Furthermore, Australia is now requiring these GFM inverters via its system strength rules.

3.5. **Question for CQTG:** We would be interested in your views on the alternative options that have been suggested, including GFM technologies.

How to treat existing generating stations under new requirements

3.6. Mercury suggested the new obligations should only apply to new generating stations and energy storage systems. They argue that many existing generating stations will not be able to physically comply with the new voltage obligations (eg, small hydro stations and old wind farms using induction machines). These existing stations are not causing major system issues and are almost certainly eligible for dispensations under the Code. Including these will result in significant workload for the asset owners and system operator (SO) in evaluating compliance, applying for and granting dispensations, with little actual benefit.

3.7. Manawa strongly favour that existing plants need to be grandfathered under all three options. Any Code changes need to consider other compliance constraints imposed, eg, resource consents are not in conflict with the Code and the type of installation and generator.

Authority should look at market-based solutions in the longer term

3.8. Meridian favours market-based options to ensure that common quality outcomes are achieved at least cost and participants are compensated for costs incurred in providing system support. Meridian's view is that none of the 3 proposed options are market-based and encourage the Authority to establish a market-based framework in the longer term to incentivise the provision of voltage support.

3.9. WEL Networks raised similar views and noted that market-based options would provide potential new revenue streams for distributed generation and distributed energy resources (DER) rather than asset owner performance obligations (AOPO) options which impose additional costs on distributed generation and DER.

3.10. IEGA also made similar comments about market-based solutions.

3.11. The Authority and the system operator had some initial discussions about this approach and have the preliminary view that voltage support is a regional issue and creating a voltage support market will likely lead to monopolies which would not have the best outcomes for all market participants.

Option 1: Assign voltage support obligations to some additional parties

Option 1: Propose to amend Parts 6 and 8 of the Code to require existing and new distributed generation, embedded generating stations, and distribution-connected energy storage systems connected to a local distribution network at a nominal voltage equal to the GXP voltage to have reactive power capability that is sufficient to meet the voltage support AOPOs specified in clause 8.23 of the Code.

Most submitters agreed that all generating units connected to the GXP should provide voltage support.

3.12. Without a Code requirement, most submitters agreed that distributors will place voltage obligations on some or all generating stations and energy storage systems that connect to their network. However, they raised concerns about the distributors ability to enforce these obligations.

3.13. Submitters agreed it would be good to standardise voltage obligations across the industry. Several submitters suggested that this could be achieved through other mechanisms, not just Code requirements. Alternative suggestions included industry guidelines by the EEA or the distribution connection and operating standards.

Authority's view on alternatives suggested to amending the Code

3.14. The Authority does not support these alternative mechanisms. Industry guidelines through the EEA would raise similar concerns about enforcing the obligations and leaving it up to each distributor to negotiate with individual generators. This would impose a significant cost on generators who may need to negotiate with several distributors. By requiring the generation to connect at a nominal voltage equal to the GXP voltage of the local distribution network, this takes into account the unique characteristics of the distribution network.

3.15. The voltage study done by Transpower demonstrated proximity to the grid improved voltage support and obligations should apply at the GXP supply bus voltage. Assets connected further away from GXP have less impact or effectiveness in controlling GXP voltage.

3.16. **Question to CQTG:** Do you agree with the Authority's view that voltage obligations are best addressed in the Code rather than through other mechanisms?

What is an appropriate capacity threshold

3.17. Orion and Lodestone suggested the threshold should be relative to each distribution network rather than a fixed value. This is because each distributor knows their network best and should be responsible for agreeing practical voltage support arrangements with generating stations connected to their network.

3.18. Lodestone suggested an alternative could be to include an overarching guideline/recommendation in the Code that include a suggested limit, but with caveats that are subject to negotiation between parties based on the needs and limitations of the connected networks.

3.19. Meridian suggested aligning the capacity threshold with the threshold adopted for frequency keeping obligations.

3.20. Powerco's view is that all generators above 1MW should have voltage support obligations and already have this mandate in place for generators to provide ±33% voltage support (through reactive power) at the point of connection. This helps them to maintain voltages within the regulatory limits and ensures the responsibility for voltage stability is shared by the parties contributing to the issue.

3.21. Transpower's view is that the threshold should be set at 5MW.

3.22. **Question to CQTG:** What would be an appropriate capacity threshold?

How to treat existing generation

3.23. Submitters have noted that not all generation technologies will have the capability to provide voltage support because of the type and the capacity (eg, induction generators). In these cases, the Authority should consider grandfathering clauses in the Code. Furthermore, existing generation already provide support to the network where it can.

Pros and cons of requiring a reactive power range of ±33% rather than the +50%/-33% range specified in the Code

3.24. Submitters did not strongly support or reject changing the reactive power range. They could see some benefits in making this change but also listed several cons, including high compliance costs for smaller renewable distribution energy projects which could discourage investment in these projects.

3.25. The EEA states that while a standardised reactive power range could improve grid stability and resilience, the proposed range might be too demanding for many renewable energy sources. More research and consideration are needed to ensure that the approach to improve voltage support does not discourage distributed renewable energy projects.

3.26. The EEA also noted that solar installations may struggle to meet this requirement without compromising their efficiency. To achieve a ±33% range, solar plants might need to operate at reduced active power output, which could reduce their overall energy yield and economic viability.

3.27. **Question to CQTG:** Should we proceed with amending the reactive power range and how much of a concern is it that this change could discourage future investment in smaller renewable generation projects or make solar generation less efficient?

Option 2: Manage the import and export of reactive power at a grid exit point

Option 2:

- Amend Part 8 of the Code to require the system operator and distributors to co-ordinate with each other in managing reactive power flows through a GXP, in either direction, in order to support voltage on both sides of the GXP.
- Amend clause 8.23 of the Code to require new and existing energy storage systems (with a point of connection to the transmission network) to be able to:
  - export and import the minimum net reactive power specified in clause 8.23 of the Code
  - continuously operate in a manner that supports voltage and stability on the transmission network.
- Amend Schedule 12.6 of the Code (default transmission agreement template) to include requirements for distributors to:
  - coordinate at all times with the system operator to manage the voltage of their connection points to the transmission network
  - ensure voltage support assets are capable of operating within a power factor range of 0.95 lagging to 0.95 leading at their connection point to the transmission network.

Most submitters agreed option 2 should be investigated further

3.28. IEGA and NewPower did not support investigating option 2 further.

3.29. IEGA reasons that the proposed change will create a conflict between the obligations in clause 8.22 and clause 8.23. The Authority does not agree with this view.

3.30. NewPower does not agree because reactive power flows are already effectively controlled by power factor limits imposed by Transpower on distributors at the GXP and the proposed extra interface between distributed generation and the system operator is unnecessary and illogical.

Costs and benefits

3.31. Submitters noted the following benefits related to option 2:

(a) Increased management of reactive power flows should help to balance the voltage profiles, while maximising the power transfer capability.

(b) Coordination of reactive power flows should help to minimise the additional reactive compensation equipment required.

(c) Investment could be deferred in network or reactive power compensation devices.

3.32. Submitters noted several costs associated with option 2:

(a) Significant costs for distributors as a DERMS system will be required for real-time visibility and forecasting.

(b) Substantial investments in new processes, tools, and methods for distributors to effectively manage voltage support across their networks.

(c) Likely to be ongoing operational costs associated with the increased complexity of managing voltage support and coordinating with the system operator.

Likely costs specifically for owners of energy storage systems with a point of connection to the transmission network

3.33. Costs for energy storage systems will be similar to other generation technologies.

3.34. Submitters noted that energy storage systems, like all inverter-based generation, incur losses when idle, unless they are in a powered-down state. If they are required to be online and available for voltage control, they should be reimbursed.

3.35. The +50% requirement is likely to impose additional costs as this is outside the range normally offered by equipment suppliers. The dispensation regime will assist with this cost and put energy storage systems on a level playing field with other forms of generation.

Option 3: Lower the 30MW threshold for generating stations to be excluded by default from complying with the fault ride through asset owner performance obligations in the Code

Option 3: Propose to amend clause 8.21 of the Code to change the threshold for generating stations to be excluded by default from complying with the fault ride through AOPOs in the Code. The changed threshold would apply to existing and new generating stations.

Submitters were supportive of lowering the threshold but there were different views of what the threshold should be.

3.36. While many supported this option, they were concerned about the significant cost involved for smaller generators to demonstrate compliance. A key theme was the disproportionate costs of demonstrating compliance for generation less than 10MW.

3.37. Some submitters suggested options to deal with this:

(a) Genesis suggested all generation must comply with the fault ride through requirements (to the extent the technology has this capacity) and generation less that 10MW should have less onerous requirements to demonstrate compliance.

(b) Lodestone suggested requiring smaller generating stations to demonstrate compliance by supplying FRT settings and asset capability documents only, not requiring them to undertake exhaustive power dynamic simulations.

(c) Vector proposed a threshold should only apply to distributed generation connected at the same voltage as the GXP, rather than across the whole distribution network.

(d) Mercury suggested a phased approach where generation less than 10MW has a requirement that the generator’s FRT specifications do not conflict with the FRT obligations in the Code; 10-30MW generation could require single machine infinite bus (SMIB) rather than full network modelling.

3.38. **Question for CQTG:** What are your views on the solutions to deal with the compliance costs for smaller generators? Should these options be investigated further?

3.39. Another concern raised by submitters is the practicality of getting existing generation to comply since the technology may not have the required capability. Manawa suggested grandfathering existing generation where it is not capable of complying. Lodestone also recommended having some leeway for existing plant to comply by having 'grandfathering' clauses in the Code that exempt already connected plant or allow a reasonable time period for compliance to be achieved.

3.40. Similar to option 1, the majority of submitters agreed that distributors are likely to place fault ride through obligations on some or all <30MW generating stations that connect to their networks, if it is not a Code requirement. Many noted that this is already happening. However, they have limited ability to enforce these obligations.

3.41. Powerco mandates all generating stations above 1MW must comply with the fault ride through requirements. Their view is that any generation above 1MW must contribute to the ability to ride through faults.

Costs are likely to be significant for owners of generating stations under the 30MW threshold.

3.42. The majority of submitters noted that the additional costs for <30MW generating stations will be significant and costly upgrades will be required.

3.43. Manawa provided more specific detail about the likely costs and estimated that the costs to model and comply with fault ride though could be between $50K- $100K per unit. Any modifications to hardware to derate will effectively put the viability of the plant at risk. The plant modifications could be from $50K - $1M or multiple of millions of dollars. More dispensations will need to be applied for with a cost to prove between $50K- $100K.

4. Next steps

General

4.1. Several submitters identified options that were not considered in the consultation document, including GFM technologies. We are interested in the CQTG's views on these options and whether we should investigate any further.

4.2. The Authority also needs to consider how any new requirements will apply to existing generation and whether existing technologies should have different requirements and the implications.

Option 1

4.3. The Authority proposes to proceed with option 1.

4.4. On balance, we think standardising voltage obligations are best addressed through amending the Code rather than guidelines or having these obligations in contractual arrangements between distributors and generators.

4.5. No clear consistent threshold came through from submitters. Powerco suggested 1MW and Transpower's preference is it should be set at 5MW. The Authority needs to look at this further.

4.6. We need to investigate further how to treat existing generation and how the new requirements will be implemented (eg, grandfathering, dispensation arrangements).

4.7. The majority of submitters did not have strong views on whether to change the reactive power range. They noted some benefits but also several cons, including potentially discouraging investment in small renewable generation. We need to discuss this further with the CQTG to determine whether we should proceed with this amendment.

Option 2

4.8. The Authority proposes to proceed with option 2.

4.9. There are several benefits to better manage the import and export of reactive power at the grid exit point (GXP).

4.10. Submitters pointed out significant costs for distributors, including that IBR will incur losses if expected to be idle to provide voltage control (rather than in a powered-down state). We are keen to seek the CQTG's views on the validity of these costs and possible ways to reduce these costs.

Option 3

4.11. The Authority proposes to proceed with option 3 – however, we will need to consider the costs it may impose on smaller generators to demonstrate compliance, especially for those under 10MW.

4.12. Submitters suggested a range of options to deal with this issue that we will discuss with CQTG.

4.13. We also need to investigate further how these requirements will apply to existing plant.

Appendix A - Summary of feedback on the consultation on voltage options

General feedback

- EEA agrees that voltage is important, but frequency is more important to address first.
- EEA consider a combination of all 3 options are needed but considers the Authority should prioritise option 1 (to address issues 2 and 3).
- Transpower's view is to prioritise extending voltage obligations and enable power factor management at the GXP (options 1 and 2) to ensure the most efficient provision of voltage management costs, and the efficient use of the power system.
- Mercury suggests the new obligations should only apply to new generating stations and energy storage systems. Many existing generating stations won't be able to physically comply with the new voltage obligations (eg, small hydro stations and old wind farms using induction machines). These existing stations are not causing major system issues and are almost certainly eligible for dispensations under the Code. Including these will result in a significant avoidable workload for the asset owners and SO in evaluating compliance, applying for and granting dispensations, with little actual benefit.

Options not considered in the paper

- The options consultation paper makes no mention of grid forming (GFM) or grid following (GFL) technologies. Currently, GFL technology is the mature technology and the first choice for developers, but this technology has drawbacks around fault ride through, and other areas not directly relevant to voltage. In a 2023 report, Transpower recommended that all IBR over 1MW should be GFM. This recommendation is based on an in-depth study of fault ride through performance of GFM and GFL. Given the other issues facing the New Zealand grid – inertia, short circuit levels, fault ride through and harmonics – a technology that can solve multiple issues (GFM inverters) should be evaluated in more depth. Australia is now requiring these GFM inverters via its system strength rules.
- IEGA suggest a market-based solution for providing voltage support. The system operator (SO) can procure voltage support and inertia from ancillary service agents. The SO already has this contractual documentation ready. Transpower has suggested this to the Authority as an option on consultation on future system operation.
- The IEGA suggests transmission-based assets to manage voltage may be the more efficient investment compared with any of the options being consulted on and suggest this should be considered before any of the proposed options are further analysed. Transpower then has direct control of the operation of these assets. There is also the possibility that Transpower may still decide to invest in these assets despite any changes to the requirements on distributed generators.

Option 1 feedback (assign voltage support obligations to some additional parties)

Question 1: Do you consider it likely that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems (when discharging) that connect to their networks? Please give reasons for your answer.

Question 2: Do you agree generating stations and energy storage systems connected to local distribution networks at the GXP voltage (which varies by local distribution network) should be required to support voltage, or do you consider the obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (eg, 33kV)? Please give reasons for your answer.

Question 3: Do you consider there should be a capacity threshold (eg, a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.

Question 4: What do you consider to be the pros and cons of requiring generating stations / energy storage systems connected to local distribution networks to have a reactive power range of ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?

Most submitters agree that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems that connect to their networks

- Standardisation across the industry is important but it does not have to be done in the Code. It could be in the form of industry guidelines by the EEA for example.
- Not all generation technologies will have the capability to provide voltage support (eg, induction generators).
- The EEA supports placing voltage support obligations on generators, especially those rated 5MW and above, but have concerns about the practicality and the fairness of implementing these obligations on existing distributed generation.
- The reasons for disagreeing:
  - If the generation isn't directly connected to the GXP, there are already requirements for voltage support on the distribution network.
  - There are already agreements in place with distribution network operators.

Most submitters support a capacity threshold (5MW or 10 MW) for generating stations and energy storage systems

- Most submitters agreed that a capacity threshold should exist with various caveats:
  - Orion and Lodestone suggested the threshold should be relative to each distribution network rather than a fixed value.

- Manawa considers the threshold should only apply to new generation because existing generation is already providing support to the network where it can.
- The threshold should align with the capacity threshold adopted for frequency keeping.

Pros and cons of requiring a reactive power range of ±33% rather than the +50%/-33% range specified in the Code

- Submitters did not strongly support or reject changing the reactive power range. They could see some benefits in making this change and some thought it would be workable for solar and wind.
- On balance, the pros of changing the reactive power range does not seem to outweigh the cons, especially if this could discourage future investment in smaller renewable generation projects or make solar generation less efficient.
- The EEA states that while a standardised reactive power range could improve grid stability and resilience, the proposed range might be too demanding for many renewable energy sources. More research and consideration is needed to ensure that the approach to improve voltage support does not discourage distributed renewable energy projects.
- Transpower's preference is to retain the existing range for synchronous generating units. They recognise that a symmetrical range would be better suited for inverter-based units. This requires further investigation to define the range.

Pros

- Implementing a uniform reactive power range across generating stations and energy storage systems would standardise voltage support across the grid, potentially improving grid stability and simplifying grid management.
- Provides more flexibility for voltage control, which can enhance the grid's ability to manage voltage levels.
- A more stringent reactive power range will make the grid more resilient to fluctuations and disturbance, which contributes to overall system reliability.
- The 33% reactive power range is reasonable and achievable based on conversations with solar developers (Orion).
- The current 50% requirement will lead to oversizing inverters to provide wider reactive range or additional costs to obtain a dispensation (Genesis).
- More international equipment will be able to be used as this complies with common international specifications (Meridian).
- The reactive power range can easily be met by generating plants without the need to install additional reactive compensation equipment, which lowers the cost for the generator asset owners (Powerco).

Cons

- Many renewable generating stations, such as solar and wind, may find it difficult to achieve this reactive power range. They are often limited in their ability to provide reactive power and may need significant and costly upgrades to meet this requirement.
- Compliance costs, especially for smaller renewable distribution energy projects, could be prohibitively high and discourage investment in these projects.

- Solar installations may struggle to meet this requirement without compromising their efficiency. To achieve a ±33% range, solar plants might need to operate at reduced active power output, which could reduce their overall energy yield and economic viability.
- The presence of harmonic filters, often necessary for compliance with other grid requirements, could further complicate achieving the proposed reactive power range. This could lead to increased complexity and cost for project developers.
- 33% is not practical and a more nuanced approach is needed. It is not practical to have a fixed reactive power range due to the effect on distribution network voltages. Generators must be able to negotiate and agree technical requirements with EDBs and receive dispensation from the SO based on that agreement (Lodestone).
- Potentially more generator assets will want to connect to the local distribution network due to the relaxed reactive power range, which may limit the size of the units. Poor power factor at the GXP can arise when there is enough embedded generation to net off the load (Powerco).

Other feedback

- The EEA pointed out potential unintended consequences in managing voltage through reactive power: There will need to be limitations on how much reactive power is used as reactive power consumes network capacity.
- Powerco is using a guideline of up to 33% MVArs. (i.e. MVArs is limited to 33% of the MWs). This is equivalent to 0.95pf, which roughly equates to 10% extra thermal load. Further work is required on how to define a reasonable deadband, and outside the deadband there would need to be a voltage droop. The volt-var mode can create unexpected upstream volt drops where X/R ratios vary along the supply route.

Option 2 feedback (manage the import and export of reactive power at a GXP)

Question 9: Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.

Question 10: What do you consider to be the main benefits and costs associated with the second voltage-related option?

Question 11: Under the second voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?

Most submitters agreed that option 2 should be shortlisted

The majority of submitters agreed with investigating option 2, except for:

- IEGA did not agree because the Code already requires distributors to be compliant with clause 8.22, requiring voltage to be supported within a maximum range of +-5% or +-10%. The proposal is that clause 8.23 applies to all generation, so distribution networks could receive instructions from the SO to support the AOPOs that conflict with how the distributor is managing its network to be compliant with clause 8.22.
- NewPower did not agree because reactive power flows are already effectively controlled by power factor limits imposed by Transpower on distributors at GXP. An extra interface for distributed generation to the transmission System Operator (TSO) as well as the distributor it is connected to is unnecessary and illogical. The TSO should control to the GXP – that is the point at the end of assets owned and under the control of Transpower. The distributor, or Distribution System Operator (DSO) should control the network that it owns beyond the GXP. Without this demarcation there will be duplication, confusion and potentially opposing instructions and obligations for connected parties. The TSO should send its requirements to the DSO who then applies their own requirements to distributed generation and distributed energy resources (including consumer connected Consumer Energy Resources).

Cost and benefits

Most submitters agreed with the costs and benefits set out in the consultation paper. Additional costs and benefits raised in the submissions are summarised in the table below.

Benefits	Costs
• Increased management of reactive power flows should help to balance the voltage profiles across the transmission and distribution networks, while maximising the power transfer capability • Coordination of reactive power flows should help with minimising the additional reactive compensation equipment required. • Being able to accommodate additional embedded generation without the need for excessive reactive power compensation equipment (as long as requirements are framed in terms of reactive power flows and not power	• Development • Implementation • New systems to coordinate, integrate and manage voltage across transmission and distribution networks. Costs for distributors: • Significant costs for distributors as a DERMS system will be required for real-time visibility and forecasting. • Substantial investments in new processes, tools, and methods for distributors to effectively manage voltage support across their networks.

factor, and open to the dispensation regime). • Deferred network or reactive power compensation devices investment. • Allows voltage management to be focussed on the GXP and helps distributors' ability to efficiently manage their networks.	• Likely to be ongoing operational costs associated with the increased complexity of managing voltage support and coordinating with the System Operator.

Likely costs arising for owners of energy storage systems with a point of connection to the transmission network

- Costs for energy storage systems should be similar to other generation technologies. However, energy storage systems, like all inverter-based generation, incur losses when idle, unless they are in a powered-down state. If units are required to be online and available for voltage control, they should be reimbursed. Online energy storage systems that are earning revenue, will integrate the losses into the offer of services. (Meridian, Genesis).
- The +50% requirement is likely to impose additional costs as this is outside the range that is normally offered by equipment suppliers. The dispensation regime in its current form should assist with this cost and put energy storage systems on a level playing field with other forms of generation (Mercury).
- Compliance and validation testing to prove capability to meet Asset Capability Statement requirements. (Powerco).

Option 3 feedback (require smaller generating stations to remain electrically connected during power system faults)

Question 12: Do you consider it likely that distributors will, in the absence of a Code requirement, place fault ride through obligations on some or all <30MW generating stations that connect to their networks? Please give reasons for your answer.

Questions 13: Do you consider it appropriate to include in the Code fault ride through curves for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account network protection considerations? Please give reasons for your answer.

Question 14: Do you consider there should be a threshold based on connection voltage and capacity (eg, a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations connected to distribution networks to ride through faults? Please give reasons for your answer, including any implications of having / not having a capacity threshold.

Question 15: Do you agree the Authority should be short listing for further investigation the third voltage-related option to help address Issue 4? If you disagree, please explain why.

Question 16: What do you consider to be the main benefits and costs associated with the third voltage-related option?

Question 17: What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if these generating stations must comply with the fault ride through AOPOs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?

Support for option 3, but with some caveats

- Overwhelming support from submitters for option 3 to be investigated further to help address Issue 4.
- The exception was Pioneer energy who was not supportive of this option and prefer the status quo to retain the 30 MW threshold. Their general view was that this option would add significant cost to smaller generators for no benefit.
- While many supported this option, they were concerned about:
  - the significant cost involved for smaller generators to demonstrate compliance
  - the practicality of getting existing generation to comply.

Without Code requirements, distributors are likely to place obligations on <30MW generating stations, but enforcement will be difficult

- On balance, submitters agreed that distributors are likely to place fault ride through obligations on some or all <30MW generating stations that connect to their networks, if it is not a requirement in the Code.
- Many already see this happening and EDBs have a strong incentive to ensure system stability and reliability (fault ride through capabilities are essential for maintaining grid resilience during disturbances).

- While distributors can have these obligations in place, without a Code requirement, they have very limited ability to enforce these obligations. This lack of enforceability could lead to inconsistency in fault ride through capabilities across different generating stations, potentially compromising the overall stability of the network.

Majority agree that there should be thresholds in the Code based on connection voltage and capacity to ride through faults

- All submitters, with the exception of Pioneer, agreed that there should be a threshold. There were different views on what the threshold should be. A key theme was the disproportionate costs of demonstrating compliance for generation less than 10MW.
- Genesis suggested all generation must comply with the fault ride through requirements (to the extent the technology has this capacity) and generation less that 10MW should have less onerous requirements to demonstrate compliance.
- Vector proposed a threshold should only apply to distributed generation connected at the same voltage as the GXP, rather than across the whole distribution network.
- Mercury suggested a phased approach to compliance:
  - Less than 10MW: The requirement could simply be that a generator's FRT specifications do not conflict with the FRT obligations in the code.
  - 10-30MW: A simplified regime could include single machine infinite bus (SMIB) rather than full network modelling.
- Orion's view is that a threshold is more relevant to voltage rather than capacity. While having both voltage and capacity thresholds could simplify compliance for smaller generators, it might miss some important contributors to system stability. Not having these thresholds ensures that all generators contribute to system stability but could place undue burden on very small generators. Voltage based thresholds might be more appropriate ensuring generators connected at higher voltages have ride through capabilities regardless of their capacity.

Costs and benefits

Benefits	Costs
• higher proportion of small generators complying with the FRT obligation will improve the stability and resiliency of NZ's power system • help prevent sympathy trips • reduced number of under-frequency events from network faults (and the associated costs with redispatch after an event) • reduced number of voltage excursion events from network faults, which reduces the risk of cascade failure	• main cost of lowering the threshold is the cost to demonstrate compliance (involves carrying out connection studies and commissioning and testing process) • seeking a dispensation and monitoring

Options to mitigate the costs:

- Require smaller generating stations to demonstrate compliance by supplying FRT settings and asset capability documents only, not requiring them to undertake exhaustive power dynamic simulations.

- Have some leeway for existing plant to comply by having ‘grandfathering’ clauses in the Code that exempt already connected plant or allow a reasonable time period for compliance to be achieved.

Likely costs for owners of generating stations under 30MW threshold

- Those that commented on this section generally made vague statements that the additional costs would be significant and costly upgrades would be required without sufficient evidence to support this argument.
- Manawa provided more specific detail about the likely costs and estimated that the costs to model and comply fault ride though could be between $50K- $100K per unit. Any modifications to hardware to derate will effectively put the viability of the plant at risk. The plant modifications could be from $50K - $1M or multiple of millions of dollars. More dispensations will need to be applied for with a cost to prove between $50K- $100K.