Options to help address the frequency common quality-related issue – Next steps

Common Quality Technical Group meeting – 17 October 2024

Contents

1. Frequency options paper feedback`

1.1. The Authority received 17 submissions on our June 2024 frequency options paper. Table 1 lists the submitters.

Table 1: Submitters on June 2024 frequency discussion paper

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

1.2. Appendix A contains a summary of submitter feedback.

1.3. The Authority considers the key points raised in submissions may be summarised as follows.

2. Option 1 – Lower the 30MW threshold for generating stations to be excluded from complying with frequency-related obligations

Challenges and limitations of specific technologies

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

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

2.3. Some submitters pointed out that many existing technologies (particularly smaller and older generation plants) may require expensive retrofitting to upgrade to meet the proposed under-frequency requirements.

Costs and financial impact

2.4. A lowering of the threshold from 30MW to 5MW or 10MW would disproportionately affect smaller generators, particularly with higher compliance costs. One submitter

estimated costs of $5-10m for upgrades, $70-100k for technical reports, and $10-100k for consent variations.

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

2.6. Dispensation costs would increase as more plants would likely require dispensations if they are unable to comply. Some submitters suggested a streamlined or less stringent compliance regime for smaller generators to reduce financial burdens.

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

2.8. However, some submitters considered that the proposal would clearly signal the requirements for future generation projects which would reduce the need for future retrofitting, and it would promote fair competition among generators.

2.9. Another submitter made the point that it would reduce the reliance on automatic under-frequency load shedding, and that maintaining the current threshold is likely to result in increased reserve costs.

Some support for market solutions

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

Compliance and monitoring challenges and suggestions

2.11. Concerns were raised about the increased monitoring and compliance costs associated with lowering the threshold. Smaller generators could be disproportionately affected by the costs associated with routine testing, administrative compliance, and control system upgrades.

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

Threshold preferences and alignment with other requirements

2.13. Some submitters raised a preference for a 10MW threshold instead of 5MW due to the alignment with the market generator requirements in the Code (clause 13.25 excludes generators from the requirement to submit an offer for generating stations that are 10MW or lower), and the performance gains from lowering the threshold to 5MW would be marginal while the costs would be significant.

Alignment of AS/NZS 4777.2 with the Code requirement for generating stations to ride through an under-frequency event for six seconds

2.14. Most comments fell into one of two categories - some submitters support the alignment, while other submitters considered that more analysis and discussion on the proposal is needed before they can form a view.

2.15. One submitter noted that 4777 is for smaller inverters, and would require significant changes to cover central inverters operating at higher voltages.

Key points to address in CQTG discussion:

2.16. Technology-specific limitations: geothermal and intermittent generators face challenges in meeting under-frequency support requirements. This seems to be due to the way in which they currently operate (fully loaded) rather than a physical limitation and can be altered. *Is this likely to always be the case? Or is it possible that these generators will/could be incentivised to operate partially loaded in future?*

2.17. Cost and financial burden: lowering the threshold increases costs for smaller generators, potentially rendering some plants financially unviable. *What are some approaches that could reduce/remove those burdens (eg, grandfathering, long lead in times, paper compliance, statistical sampling, risk-based compliance etc)?*

2.18. Market based approach: *is this a realistic option as part of this project?*

2.19. Threshold preference: *10MW or 5MW?*

3. Option 2 – Set a maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve

Uniform vs technology-specific deadbands

3.1. Several submitters prefer a uniform deadband for all technologies as they consider it would simplify system management. However, some consider that exclusions should be made for some technologies (eg, geothermal) to protect their design lifetimes.

3.2. Other submitters argue that different technologies contribute differently to the system. For instance, synchronous generators provide stability (eg, inertia, voltage support) and should not face tighter deadband requirements that are better suited for IBR. They also mention that wind turbines are particularly prone to excessive wear and tear from small deadbands.

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

3.4. Another submitter noted that even within technologies, there can also be significant variance due to specific components or model types (eg, Kaplan vs Francis hydro turbines).

Widening the normal frequency band

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

3.6. However, many disagree with widening the normal band due to:

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

(b) the perceived benefits being minimal or unknown

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

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

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

(f) deadband policies may be a more effective alternative.

Implementation costs and challenges

3.7. The cost of implementing deadbands varies significantly depending on the type of generation. Geothermal and wind could face high costs due to wear and tear, energy spillage and equipment upgrades.

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

3.9. There would likely be an increase in dispensation applications from asset owners in relation to plants that are unable to comply with the new requirements, as well as compliance monitoring, validation testing and certification to demonstrate capability.

3.10. Some submitters suggested a phased implementation or simplified testing requirements. There are limited resources for testing and implementing changes in the industry, so a managed approach may be necessary for the industry to effectively transition to new requirements.

3.11. A uniform deadband would simplify system management, reducing costs. Dispensations could be considered to manage deviations.

Long-term vs interim solutions

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

Impact on equipment

3.13. Concerns were raised that tighter deadbands could lead to increased wear and tear on certain technologies like wind turbines, which could reduce their lifespan. BESS used for frequency regulation could also have a reduced state of charge and shortened lifespan, impacting its ability to meet peak demand.

3.14. Implementing deadbands on geothermal units was seen as impractical as they consider they are better utilised when fully loaded.

Frequency response and ramp rates

3.15. There is some support for minimum ramp rates, which would ensure that generators of similar technologies can provide consistent frequency responses to each other. Additionally, there was a suggestion to restructure the instantaneous reserve market to better incentivise IBR to contribute to frequency control.

3.16. Submitters against option 2 were mainly concerned about:

(a) the implementation costs, particularly for older plants that do not have the required equipment

(b) the potential delay to moving to a market-based solution.

3.17. There appears to be over all support for option 2, as long as the Authority implements any new requirements in a way that does not affect existing plants.

4. Option 3 – Procure more frequency keeping and instantaneous reserve under status quo arrangements

Main benefits of option 3 identified by submitters

4.1. Some submitters believe that using existing services for frequency control may be more efficient than creating an entirely new capability market because it would just require the amounts to be adjusted, especially with technologies such as batteries and interruptible loads.

4.2. Modern technology is expected to provide increased reserves. This could help offset procurement costs and improve system performance.

4.3. Option 3 would improve frequency support when needed.

4.4. The flexibility of option 3 allows participants to assess the risk/benefit of offering into the MFK service and adjust their operations based on plant-specific capabilities. It also provides transparency on the economic costs of frequency management.

Main costs of option 3 identified by submitters

4.5. Some submitters noted the opportunity cost of not developing a capacity market for frequency services, which could better incentivise battery projects and further stabilise system frequency.

4.6. Option 3 doesn't solve the underlying issue of frequency fluctuations, it is a management tool. This could lead to higher reserve costs as more intermittent generation comes online.

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

4.8. There was support for creating a very fast (1 second) reserve category, which would help mitigate the reduced inertia in the system.

Additional points raised

4.9. Consider widening the criteria under which the system operator can call on units to run in synchronous condenser mode, which would provide more flexibility to stabilise frequency.

4.10. Improved real-time integration between transmission system operators and distribution system operators to better monitor embedded generators within distribution networks.

4.11. Modern technology can provide a frequency maintenance service without being dispatched.

4.12. Amending the Electricity (Safety) Regulations 2010 to require earth faults to be cleared in less time (currently 5 seconds) would help to provide quick protection responses when inertia is lower.

4.13. A critical feature to prioritise is the capability for frequency and voltage capability ride-through, which should apply to all distributed generation (including residential).

Appendix A – Summary of feedback on the consultation on frequency options

This appendix contains a summary of submitters' feedback for each question in the Authority's June 2024 frequency options paper.

	Submitter	Summary of the response
	Question 1 • Do you agree the Authority should be short listing for further investigation the first frequency-related option to help address Issue 1? If you disagree, please explain why.	
1.	Lodestone Energy	Agrees with shortlisting the option, however notes that intermittent generation may not be able to provide under-frequency support when there is no fuel. Wants to avoid pre-event curtailment, which is not being proposed but has been investigated by Transpower. Wants to remove the 45Hz fault ride-through (FRT) requirement in the South Island.
2.	Contact Energy	Disagrees with shortlisting this option, because it's impractical for some generation technologies like smaller geothermal units which cannot operate partially loaded. However, they can respond to over-frequency and contribute to system inertia.
3.	SolarZero	Disagrees with shortlisting this option. Favours creating a market for frequency services to achieve the most efficient outcomes. Recommends compensating participants for providing these services to reduce imposed costs.
4.	Genesis Energy	Agrees with shortlisting this option in principle and supports a 5MW threshold. For units below 30MW, the asset owner should review the capability of each generating unit to determine the extent to which it can comply. Expects dispensations to be granted and associated costs to be waived for units that cannot comply.
5.	Independent Electricity Generators Association (IEGA)	Disagrees with shortlisting this option. Believes the system operator's analysis is inconclusive and the proposal could negatively affect the financial viability of intermittent generators below 30MW, deterring investment in new generation projects.
6.	Manawa Energy	Disagrees with shortlisting this option, considers that the costs outweigh the benefits. Manawa would face challenges with complying due to their machine types and frequency management systems.
7.	Mercury Energy	Agrees with shortlisting this option but supports a 10MW threshold rather than 5MW as the performance benefits are only marginally lower. A 10MW threshold would also better align with the market generator requirements under the Code (clause 13.25 excludes generators from the requirement to submit an offer for generating stations that are 10MW or lower).

8.	Meridian Energy	Agrees with shortlisting this option, considers that it would help to maintain system frequency and promote fair competition among generators. Preference for the change to be implemented in the Code, rather than on a station-by-station application from the system operator. A Code requirement would more clearly signal the requirements for smaller plants to future investors.
9.	Pioneer Energy	Disagrees with shortlisting this option, Pioneer's stations are unable to provide improved frequency support due to consent requirements and water management regulations that limit their operational flexibility.
10.	Powerco	Agrees with shortlisting this option.
11.	Transpower	Agrees with shortlisting this option, to better manage frequency risks from increasing distributed energy resources (DER) and avoid reliance on automatic under-frequency load shedding (AUFLS). Notes that other jurisdictions have already lowered their thresholds, and failure to follow will increase reserve costs.
12.	NewPower	Disagrees, does not consider that any studies have been done on the impact of grid-connected excluded generating stations on system frequency. Option 1 causes issues for intermittent generators under 30MW. It would require operating partially loaded, or co-locating BESS, neither of which are efficient.
	Question 2 • What do you consider to be the main benefits and costs associated with the first frequency-related option?	
13.	Lodestone Energy	Benefits: • Standardisation and clarity Costs: • Fixed compliance costs (eg, consultant studies) which disproportionately impact smaller generators.
14.	Contact Energy	Benefits: • Reduced procurement costs Costs: • Increased operational costs for asset owners and the system operator, resulting from the increase in applications for dispensation • Higher lead times for the compliance assessment of new generations connections, due to the impact on the system operator's resources.
15.	SolarZero	Benefits: • Uncertain Costs: • No comment.
16.	Genesis Energy	Benefits: • Reduces the amount of fast instantaneous reserve (FIR) required

		Costs: • Dependent on how much generation under 30MW is expected to trip without the change.
17.	IEGA	Benefits: • No comment Costs: • Cost of upgrading equipment • Costs associated with dispensation process • Additional costs to the system operator for assessing compliance, possibly requiring upgrades to tools such as the Reserve Management Tool (RMT) • Consultancy fees, which would be expected to increase due to the sudden increase in demand (creating a relative shortage of consultants) • Delays to the completion of new generation projects, due to the increased resourcing needs from the system operator • Possible reduction in new projects due to the higher barriers for smaller generation.
18.	Manawa Energy	Benefits: • No comment Costs: • Retrofitting of equipment • Ongoing costs of compliance • Consent variation costs • Costs associated with the dispensation process.
19.	Mercury Energy	Benefits: • No comment Costs: • Studies to ensure the plant is stable • Equipment upgrades • Commissioning and testing the equipment's performance • Wear and tear from responding to frequency-related obligations.
20.	Meridian Energy	Agrees with the Authority's summary of costs and benefits.
21.	Pioneer Energy	Benefits: • No benefits Costs: • Significant capital and operational costs, making compliance financially prohibitive.
22.	Powerco	Benefits: • Promotes compliance with asset owner performance obligations (AOPOs) • Contributes to grid stability and fairness Costs:

		• Minor expected costs for inverter-based resources (IBR) • High expected costs for smaller conventional generation.
23.	Transpower	Benefits: • Reduces the costs of reserves • Mitigates the risk of sympathetic tripping Costs: • Administrative compliance and control system upgrades for smaller generators (5-30MW) • Additional monitoring costs to the system operator.
24.	NewPower	Benefits: • unknown reduction in reserves Costs (approximately $150-200k per plant): • consultant fees for dynamic studies • control system changes and pre-testing • on-site frequency response testing • compliance summary report • equipment upgrades • dispensation process • spilled energy or co-locating BESS • possible delays to the completion of new projects
	Question 3 • What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?	
25.	Lodestone Energy	Lowering the threshold to 10MW would disproportionately affect smaller generators with higher compliance costs. The 5MW recommendation lacks a strong justification.
26.	Contact Energy	Lowering the threshold will impose dispensation costs on plants that can't meet the new requirements.
27.	SolarZero	Unsure of the exact costs without more information.
28.	Genesis Energy	Minimal direct costs for generators under 30MW as modern technologies typically are designed with the necessary equipment to enable them to comply by reconfiguring their settings. However, smaller generators may face significant compliance costs, especially in demonstrating compliance. Supports a streamlined compliance and monitoring regime for smaller generators.
29.	IEGA	Routine testing and increased monitoring costs will disproportionately affect smaller generators, particularly intermittent ones if they are required to operate sub-optimally. Significant upgrades, such as energy storage systems will likely be needed to comply.
30.	Manawa Energy	Estimated $5-10m for upgrades, $70-100k for technical reports, and $10-100k for consent variations. Lowering the threshold could make some plants unviable due to compliance costs, even with a dispensation.

31.	Mercury Energy	Recommends a less stringent compliance regime for smaller generators to reduce costs, encouraging them to operate with frequency performance that is consistent with the Code but not mandated.
32.	Meridian Energy	Expect significant costs for equipment upgrades, control modifications and testing. Compliance costs could be disproportionately high compared to the benefits.
33.	Pioneer Energy	Individual assessment is needed for each station as costs are expected to be significant, with few stations being standardised.
34.	Powerco	Virtual power plants will face additional compliance costs, including monitoring and control systems, but these costs are likely to have already been factored into their operational plans. The growing number of generators may also lead to higher costs for coordination and frequency keeping.
35.	Transpower	Administrative costs for generators will rise including preparing asset capability statements, conducting connection studies and complying with system operator commissioning and testing processes. Equipment upgrades might also be necessary.
36.	NewPower	Routine testing and provision of additional ACS information. Cost of spilled energy from operating partially loaded, or the cost of co-locating BESS. Increased costs associated with establishing an ICCP connection for each site. Increase in consultancy fees due to the increased demand.
	Question 4 • What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an under-frequency event for six seconds?	
37.	Lodestone Energy	Supports alignment with international standards in principle.
38.	Contact Energy	No comment because they are unfamiliar with the standard.
39.	SolarZero	No position due to insufficient information provided, but suggests the Authority work closely with the standards committee.
40.	Genesis Energy	AS/NZS 4777.2:2020 places more stringent requirements than the Code, so if anything, it is the Code that should be updated to align with 4777.
41.	IEGA	Supports NewPower's submission.
42.	Manawa Energy	More analysis and discussion are needed regarding the inclusion of AS/NZS 4777.2:2020 in the Code.
43.	Mercury Energy	Supports alignment and sees potential to leverage evolving technologies like electric vehicles for frequency response.
44.	Meridian Energy	No position due to limited discussion in the consultation paper.
45.	Pioneer Energy	Concerned that costs for currently non-compliant stations could be high, with minimal benefit.

46.	Powerco	Supports alignment as it helps stabilise the grid and promotes consistency across the energy sector but acknowledges potential costs for some inverters.
47.	Transpower	Supports alignment, noting that it promotes consistency with international standards, simplifies equipment procurement and ensures under-frequency ride-through requirements for small-scale inverters.
48.	NewPower	Ther is no obvious need to align 4777 and the Code as long as the system operator can properly account for the performance of inverters compliant with AS/NZS 4777.2. This standard is for smaller inverters, and would require significant changes to cover central inverters operating at higher voltages.
	Question 5 • Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	
49.	Lodestone Energy	Disagrees, favours a technology-neutral approach.
50.	Contact Energy	Agrees, but considers that thermal and geothermal should be excluded to maintain reliability and meet design lifetimes of that plant. Wind turbines will also need to be considered as a small deadband will result in excessive wear and tear. Does not anticipate any issues for solar and BESS.
51.	SolarZero	Disagrees, views the proposal as technology-specific which does not align with the Authority's objectives.
52.	Genesis Energy	Agrees, IBR are capable of complying with a tighter deadband and provide a faster response. The tighter deadband should not be applied to synchronous generators, which contribute in other ways (eg, inertia, voltage stability). Wants minimum ramp rates to be introduced, to ensure that generators with similar technologies will provide similar responses. Also wants the instantaneous reserve market to be restructured.
53.	IEGA	Does not support option 2. Believes that regulation needs to take into account the technology, rather than a blanket approach.
54.	Manawa Energy	Agrees with applying a deadband if it can be reasonably achieved but need to consider limitations of existing generation plants.
55.	Mercury Energy	Does not favour a mandated dead band, but if it is mandated then Mercury would support a technology-specific approach. Different technologies incur varied costs to meet frequency regulations (eg, Kaplan vs Francis hydro turbines).
56.	Meridian Energy	Agrees, but favours maintaining current requirements until a market-based solution is developed. Imposing interim changes risks increasing system costs without sufficient benefits. The current requirements should be maintained for wind generation to avoid wear and tear from a disproportionate workload. BESS should only be used for frequency keeping as a last resort as it's better utilised to provide reserves, and the impact on its lifespan and warranty terms.
57.	Pioneer Energy	Agrees, different technologies provide varying levels of frequency response.
58.	Powerco	Agrees, different technologies should have different requirements, particularly for IBR. This would optimise benefits without compromising existing generation.
59.	Transpower	Disagrees, prefers a uniform deadband to simplify system management. Dispensations can be considered to manage deviations, ensuring consistent frequency management.

60.	NewPower	Agrees, due to the capabilities of different technologies. BESS deteriorates quicker than other generation types, and reduce the amount of charge it can hold which could result in lower reserve amounts. BESS will need to receive frequency keeping revenue at least equal to degradation and opportunity cost of arbitrage.
	Question 6 • Do you consider the Authority should be short listing the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	
61.	Lodestone Energy	No comment.
62.	Contact Energy	Agrees, noting that the current band is a legacy of frequency dependent loads on the system.
63.	SolarZero	Disagrees, considers the normal band should only be changed as part of implementing a frequency management market.
64.	Genesis Energy	Disagrees, considers the flow on effect may be an increase in the amount of reserves needed due to the greater risk of triggering an AUFLS event.
65.	IEGA	Disagrees, does not support option 2.
66.	Manawa Energy	Disagrees, citing minimal/unknown benefits depending on the set up of individual machines.
67.	Mercury Energy	Disagrees, believing that some of Transpower's assumptions are conservative and therefore the need for increases in frequency keeping will not eventuate as quickly as Transpower expects.
68.	Meridian Energy	Agrees, considers the Authority's previous analysis is outdated and it would be valuable to reconsider with current market rules and technologies.
69.	Pioneer Energy	Disagrees, considers it could worsen synchronisation challenges for generators that do not have governors.
70.	Powerco	Agrees, noting minimal negative impacts due to the attributes of modern loads. However, there may be costs for asset owners to adjust frequency response characteristics, so additional frequency response studies might be necessary.
71.	Transpower	Disagrees, favours deadband policies instead. New Zealand already has a wide normal band compared to other jurisdictions.
72.	NewPower	Agrees, considers the normal band may not be optimal anymore.
	Question 7 • Do you agree the Authority should be short listing the second frequency-related issue? Please give reasons with your answer.	
73.	Lodestone Energy	Agrees.
74.	Contact Energy	Agrees, as long as it excludes certain technologies. Supports combining option 2 and option 3.

75.	SolarZero	Disagrees, considers that a market-based solution is the most efficient option.
76.	Genesis Energy	Agrees.
77.	IEGA	Disagrees, only supports option 3.
78.	Manawa Energy	Agrees, but only for new plants because their frequency control systems will be relatively easy to program. Does not support a maximum deadband for existing generation.
79.	Mercury Energy	Disagrees, there would be high costs for certain technologies such as geothermal (increased wear and tear, spilt energy, reduced efficiency on units with reduced deadbands). Mercury also does not consider that the current system is broken because asset owners currently are required to agree settings with the system operator. If the proposal were to proceed, Mercury recommends a phased implementation and simplified testing/submission requirements as there is currently limited resource in the industry.
80.	Meridian Energy	Disagrees, favours moving directly to a capability market instead of mandating deadbands. Believes the current management is adequate for now.
81.	Pioneer Energy	Disagrees.
82.	Powerco	Agrees.
83.	Transpower	Agrees, it is necessary to provide clarity and prevent generators for using overly wide bands, which could harm system stability. A ±0.1 Hz deadband for new generators is recommended.
84.	NewPower	Potentially. NewPower prefers the permitted deadband to be the same as the normal frequency range (ie, ±0.2 Hz). A deadband smaller than this would have unintended consequences for some generation types, so more consideration of the costs would be needed for each type.
	Question 8 • What do you consider to be the main benefits and costs associated with the second frequency-related option?	
85.	Lodestone Energy	No comment.
86.	Contact Energy	Sees benefits for generation that is able to comply, but unnecessary dispensation costs for generation that cannot comply.
87.	SolarZero	None. Does not believe option 2 is cost-effective.
88.	Genesis Energy	A maximum deadband will improve frequency regulation and reduce the risk of power outages during credible and non-credible contingency events.
89.	IEGA	Supports NewPower's submissions.

90.	Manawa Energy	Sees no benefit for existing plants unless they are easily programmable. The cost to upgrade equipment would be significant, and additional study would be required to identify options.
91.	Mercury Energy	Significant costs would be imposed. Geothermal, wind and solar are likely to face energy spillage, and implementing a ±0.1 Hz deadband is likely to be complex for some technologies due to plant interactions. Implementing a governor response on geothermal units would be impractical. The momentary reduction in output would have implications for steam, binary fluid, system design and control, all of which has an impact on compliance costs, fuel costs and efficiency.
92.	Meridian Energy	Considers that the Authority may have underestimated costs, particularly on wind turbines due to the increased wear and tear and reduction in their lifespan.
93.	Pioneer Energy	Expects that the costs would be very high, and the performance benefits would be minor.
94.	Powerco	Considers the proposal would be cost-effective, especially as it accounts for differences in generation technology. The cost-effectiveness is expected to improve over time.
95.	Transpower	Notes that lowering the deadband will reduce frequency-keeping costs. However, some asset owners may incur costs for adjusting deadbands and updating models, and generators with narrow inherent deadbands could face wear and tear issues.
96.	NewPower	Benefit would be clarification of the requirements, and consistent application by generation owners. The costs are: • increased dynamic studies by consultants • compliance and testing • wear and tear (particularly for BESS) • opportunity cost for BESS (providing reserves) • cost of complying (spilled energy or co-locating BESS)
	Question 9 • What costs are likely to arise for the owners of generating units if a permitted dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	
97.	Lodestone Energy	No comment.
98.	Contact Energy	Sees benefits for generation that is able to comply, but unnecessary dispensation costs for generation that cannot comply.
99.	SolarZero	Considers that a market-driven approach for frequency services is the most cost-effective option.
100.	Genesis Energy	Additional costs will vary depending on the generation technology. Some generators would need to contract an equivalent response from another generator, however those costs may be offset by the ability to offer reserves with the same capacity.
101.	IEGA	See NewPower's submission.

102.	Manawa Energy	Costs will vary across stations, making it difficult to provide an accurate estimate without costly studies. For existing plants, Manawa estimates costs to be $5-10m for equipment upgrades, $70-100k for technical reports, $10-100k for consent variations, as well as additional ongoing costs.
103.	Mercury Energy	There would be spillage from geothermal, wind and solar generation.
104.	Meridian Energy	Increased wear and tear on wind turbines in particular, and energy spillage during dry periods when hydro storage is trying to be preserved.
105.	Pioneer Energy	Studies would be required to provide an accurate estimate of costs, particularly as the costs are likely to vary for each station.
106.	Powerco	Costs include upgrades to generation units, compliance monitoring, validation testing and certification to demonstrate capability.
107.	Transpower	For generators with hardware-based inherent deadbands, upgrading to comply with new requirements could be costly, as these deadbands are typically tied to the equipment's hardware.
108.	NewPower	Control system changes and compliance testing, including possible control system upgrades/replacement (approximately $100-300k+). Costs associated with the dispensation process.
	Question 10 • What do you consider to be the main benefits and costs associated with the third frequency-related option?	
109.	Lodestone Energy	Benefits: • No comment Costs: • The opportunity cost of developing a capacity market for frequency control services instead. This would better incentivise battery storage projects and improve system frequency performance as more battery projects come online.
110.	Contact Energy	Benefits: • Utilises existing and proven market services, which may be more efficient than introducing an additional capability market for control response. • The increasing supply of reserves coming onto the system (in the form of interruptible load and BESS) would help to offset the costs of increasing the quantity of reserves. Costs: • No comment.
111.	SolarZero	Benefits: • No comment Costs: • Modern technology can already provide a synthetic governor response without being dispatched. • The opportunity cost of a more fundamental review of frequency management.
112.	Genesis Energy	Benefits: • No comment Costs:

		• It does not directly resolve the issue of more frequency variability, so it may result in a higher chance of unintended outcomes.
113.	IEGA	Benefits: • See cover letter Costs: • No comment.
114.	Manawa Energy	Benefits: • See cover letter / analysis in Paper A • Provides an opportunity to add capability for additional frequency response services, and to incorporate this into the design of new generation plants. Costs: • No comment.
115.	Mercury Energy	Benefits: • The status quo is known, and the quantities can be adjusted as necessary. Costs: • The current frequency keeping band requirement is consistent across all time periods, which may not always be appropriate.
116.	Meridian Energy	Benefits: • The existing arrangements are known, provide transparency on the economic costs of frequency management, and allows providers to factor these costs into their market offers. Costs: • No comment.
117.	Pioneer Energy	Benefits: • Allows asset owners to focus improvements where they are economically feasible. • Offers flexibility in accepting new technological solutions and targeting them to locations with the highest need. Costs: • No comment.
118.	Powerco	Benefits: • Improves frequency support during contingent events. Costs: • As the proportion of IBR continues to increase, the amount of reserves needed (or equivalent measures) may continue to increase.
119.	Transpower	Benefits: • Ensures stable frequency quality. Costs: • Might lead to the need for a wider frequency band. • Lacks the benefits that deadband settings can provide.
120.	NewPower	Benefits: • Requires little to no Code changes • Provides visibility on frequency keeping costs Costs: • No comment.
	Question 11 • Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	

121.	Lodestone Energy	No comment.
122.	Contact Energy	Agrees with the Authority's assessment of option 3.
123.	SolarZero	Prefers option 3 but considers that it needs more work, and that the ideal solution is to create a new market rather than specifying performance requirements.
124.	Genesis Energy	Option 1 partially addresses the issue, but more action would be required to reduce the risk of load shedding. Genesis supports a reform of the instantaneous reserve market, particularly the creation of a very fast (1 second) reserve category to offset the impact of decreasing inertia, and an increase in the rate of change of frequency following an AC contingency event.
125.	IEGA	Considers that the Authority's assessment demonstrates that option 3 is the preferred option.
126.	Manawa Energy	Prefers option 3, the costs associated with options 1 and 2 are too high and would significantly impact the commercial viability of some stations. The consultation paper does not acknowledge the diversity of existing generation plants, and modifying them would require expensive, tailored upgrades in order to comply (if it is achievable at all). Reducing the 30MW threshold is unlikely to provide a significant benefit because many of the plants under this threshold would be physically unable to comply.
127.	Mercury Energy	It may be prudent to consider widening the criteria under which the system operator is able to call on units to run in synchronous condenser mode. Recommendation to keep frequency keeping cost allocation simple in order to avoid unintended consequences from an overly complex methodology.
128.	Meridian Energy	Agrees with the Authority's overall assessment and supports option 3 as the preferred option. However, disagrees with the assessment of option 3 against criteria 3. While geothermal plants may have higher frequency-keeping costs, this does not mean the approach is not technology neutral. Instead, it allows each technology to offer services based on its capability and associated costs. Supports further investigation into procuring frequency-related services from new IBR, particularly a 1 second reserve market product. This presents an opportunity to foster new capabilities from emerging technologies to support system stability.
129.	Northpower	Considers that the system operator's studies are reliable. Concerned about the financial impacts of requiring existing generation to comply with a lower threshold, which would require significant investment.
130.	Pioneer Energy	Embedded generators are unlikely to be able to easily comply with options 1 and 2, unless costly upgrades are made.
131.	Powerco	Improved real-time integration between transmission system operators and distribution system operators is crucial. This would allow the TSO to monitor embedded generators' operations within distribution networks, promoting a holistic approach to system operation.
132.	Transpower	The Authority has made pragmatic choices in shortlisting options for addressing electricity transition issues, prioritising timely solutions. While some system operations-related concerns have been addressed, there are still outstanding options to consider.

133.	Aurora Energy	Amending the Electricity (Safety) Regulations 2010 to require earth faults to be cleared in less time (currently 5 seconds) would help to provide quick protection responses when inertia is lower.
134.	Electricity Engineers' Association	Agrees with the outline in the consultation paper and considers options 1 and 2 should be investigated further. A critical feature to prioritise is the capability for frequency and voltage capability ride-through, which should apply to all distributed generation (including residential).
135.	King Country Energy	The cost to upgrade existing assets to comply with options 1 and 2 would be substantial.
136.	NewPower	BESS would be more incentivised to enter the frequency keeping market if it was sized based on total frequency keeping need.