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To: The Electricity Authority
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Review of Common Quality Requirements in the Code – Genesis Response

Genesis Energy Limited **(Genesis)** welcomes the opportunity to comment on the consultation papers published by the Electricity Authority (**Authority**), relating to the review of Part 8 of the Electricity Industry Participation Code (**the Code**).

A summary of Genesis' response to each paper are provided below. A full response to the questions outlined in each paper are provided in Table 1, Table 2 and Table 3.

Addressing more frequency variability

Genesis supports in principle a requirement for new and existing generating stations greater than 5 MW to comply with frequency related obligations and for the introduction of a maximum permitted dead band, subject to further clarification of the following aspects:

1. The approach to assess and monitor compliance for generation between 5 and 30 MW;
2. How the proposed amendments will consider the different capabilities offered by each generation technology.
3. The extent to which the proposed amendments will apply to existing generation.

Genesis does not support the widening of the normal band, or the procurement of more frequency keeping, as neither option addresses the primary issue of more frequency variability or the associated reduction in system stability.

Addressing larger voltage deviations / network performance issues

Genesis supports in principle the requirement for all new generation, irrespective of size, to have voltage support and fault ride through obligations, to the extent the generation technology used has this capability.

We support further investigation by the Authority to clarify the following details around the proposed amendments:

1. The requirements applicable to each generation technology, and the threshold to which it should apply.
2. The extent to which the proposed amendments will apply to existing generation.

With respect to the circumstances in which a generator or energy storage system is required to provide voltage support, we request the Authority to consider altering the proposed amendments to allow for reimbursement for electricity consumed by a generator or energy storage system, whenever idle and not dispatched for an ancillary service.

The Governance and management of harmonics

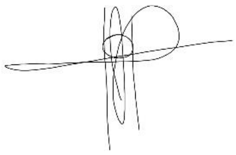
There is significant ambiguity around the governance of harmonics, with a poor alignment between legislation, the Code, and other rules, regulations and guidelines applicable in New Zealand. Genesis supports efforts by the Authority to improve the alignment in the governance of harmonics, and generally supports the adoption of the AS/NZS 61000 series. However, certain sections of the AS/NZS 61000 series are intended to be more informative and should not be interpreted as mandatory requirements to avoid any unintended consequences.

There appears to be increasing scrutiny on harmonic emissions from generation, while there is less scrutiny, in our view, of changing emissions from gradual changes to consumer and industrial load. More awareness is needed of the correlation between emissions from individual participants and the prevalence of harmonic issues, to fairly attribute costs according to the extent that each participant contributes.

With respect to harmonics management, we believe it would be more effective to substitute a harmonic allocation methodology for increased monitoring and continuous automated assessment strategy, as a single upfront assessment is incapable of forecasting how a generator's harmonic emissions will change over its lifetime.

Genesis supports further investigation of an open access approach as in our view, it will result in the best outcomes for New Zealand (for consumers, network owners and generators). Implementation of a centralised harmonic measurement database will be essential in ensuring this approach is fair to all stakeholders, while equipping transmission and distribution network companies with the tools they need to ensure the electricity network continues to operate as intended. While the costs to implement a centralised database may be significant, we expect these costs would be minimal compared to the savings obtained through minimising the need for additional harmonic filters.

Yours sincerely,



Matt Ritchie
GM Government Relations and Regulatory Affairs

Table 1: Addressing more frequency variability in New Zealand’s power system – Genesis response

Question Number	Question	Genesis response
1.	Q1. 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?	Yes, Genesis supports in principle a requirement for new and existing generating stations greater than 5 MW to comply with frequency-related obligations, subject to further investigation of the approach taken to assess and monitor compliance, as explained in our response to the following questions. With respect to existing generation with capacity of less than 30 MW, we support an obligation for the asset owner to review the capability of each generating unit, to assess the extent to which it can comply with the frequency obligations outlined in Part 8 of The Code. Should an existing generating unit be unable to comply, then we would expect a dispensation would be granted retrospectively, and for associated costs to be waived.
2.	Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	We agree with Transpower’s finding that lowering the MW threshold for complying with frequency obligations will reduce the amount of Fast Instantaneous Reserve (FIR) required. However, the incremental benefit is dependent on the amount of generation that is expected to trip without lowering the threshold (in their study, Transpower estimates this to be 20% of generation with capacity of less than 30 MW).
3.	Q3. 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?	We anticipate minimal additional direct costs for new generators with capacity of less than 30 MW to comply with frequency obligations outlined in the code, for the following reasons: • Most modern generating technologies can be configured with appropriate protection settings to maintain power output for the normal and transient frequency ranges specified in the code, with a relatively standard procurement specification. • Most modern generating technologies are equipped with a frequency control system, which is capable of increasing power output during under frequency events, provided the power available from the primary energy source exceeds the pre-disturbance output. However, the additional indirect costs incurred by generators with capacity of less than 30 MW will depend on the level of proof required to demonstrate compliance: • Significant costs will be incurred by smaller generators (as a proportion of their size), if compliance is to be assessed and monitored in the same way as generators over the 30 MW threshold. • Compliance costs for larger generation will increase, due to a higher demand for engineering support related to compliance activities.

		We suggest the following options could be investigated for assessing and monitoring the compliance of generators with capacity of less than 30 MW, to balance the benefit gained with the cost incurred: 1. Allow compliance to be demonstrated by review of proposed/applied settings, without observation of simulation or test results. 2. Create an aggregate MW output signal for all generation between 5 and 30 MW and monitor the combined response during and after frequency excursions. This information can then be used to monitor compliance, and optimise the procurement of reserves, without requiring routine testing for each generator.
4.	Q4. 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 underfrequency event for six seconds?	AS/NZS 4777.2:2020 already requires for inverters to remain in continuous operation for a frequency range that exceeds the requirements in section 8.19 (1) of The Code. Accordingly, we do not see a need to undertake further review of the alignment between these documents and support the code being aligned with AS/NZS 4777.2:2020 for inverter-based technology.
5.	Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	We advocate for a permitted maximum dead band requirement to be technology specific, given inverter-based generation technologies are capable of a tighter deadband and faster response rate. We believe it is fair to require inverter-based generation to use a tighter dead band, while not extending these more onerous requirements to synchronous generation. Synchronous generation contributes to stability in other ways, such as the provision of inertia, stabilising the voltage waveform, and contributing higher fault currents to ensure existing protection schemes operate correctly. In addition to the introduction of a permitted dead band requirement, there needs to be additional requirements around the minimum ramp rate permitted for each generation technology, like what is required in Australia[1], [2]. Specification of the minimum response rate for each generation technology will ensure that two generators with the same technology provide a similar response rate, according to their capability. Irrespective of the approach for introducing a permitted maximum deadband requirement, we believe the instantaneous reserves market needs to be restructured, to ensure there is incentive for inverter-based generation to provide fast acting frequency regulation capability.
6.	Q6. 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.	We do not support short listing the widening of the normal band, as its implementation may lead to unintended outcomes. Widening the normal band may lead to a contingency event where the pre-disturbance frequency is closer

[1] Refer to Primary Frequency Response (PFR) Requirements, Section 3.4 (https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/primary-frequency-response-requirements/final-docs/primary-frequency-response-requirements.pdf?la=en).

[2] Refer to Market Ancillary Services Specification, Section 3.11 (https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/2024/market-ancillary-services-specification---v82-effective-3-june-2024.pdf?la=en).

		to 49.8 Hz, making it necessary to procure more frequency reserves to avoid activating the Automatic Under-Frequency Load Shedding (AUFLS) scheme.
7.	Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why. Addressing more frequency variability in New Zealand's power system.	We agree the Authority should be shortlisting the second frequency-related option to help address the issue of more frequency variability with increasing amounts of intermittent generation.
8.	Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	Introduction of a maximum permitted dead band will improve frequency regulation, reducing the risk of power outages during credible and non-credible contingency events.
9.	Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	Additional costs will vary depending on the generation technology. Some generators (i.e. those with high inherent dead band) would need to contract an equivalent response from another generator, however these costs may be offset by the ability to offer reserves with the same capacity.
10.	Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	We do not support procurement of more frequency keeping, as it does not address the primary issue of more frequency variability, which may lead to the unintended outcomes outlined in Q6.
11.	Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	We note that the studies performed by Transpower show the maximum frequency deviation from a credible AC contingency event reduces from 49 Hz in 2023 to 48 Hz in 2035. While the implementation of option 1 partially addresses this issue, we believe that further action will be required to reduce the risk of load shedding. We support in principle a reform of the instantaneous reserves 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. Evidence from Australia demonstrates this approach (in conjunction with a tighter dead band) is effective at managing frequency regulation and improving frequency stability. The addition of a new instantaneous reserves market (1 second) would help enable and accelerate modern generation technologies into the market

Table 2: Addressing larger voltage deviations and network performance issues in New Zealand's power system – Genesis Response

Question Number	Question	Genesis response
1.	Q1. 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.	If voltage support obligations are left to the Electricity Distribution Business to determine, then this may lead to inconsistent practices across New Zealand, adding uncertainty for planned generation.
2.	Q2. 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.	We support in principle the requirement for all new generation, irrespective of size, to support the voltage on the network to which it is connected, to the extent the generation technology used has this capability. We acknowledge some generation technologies, such as induction generators, do not support system voltage. As induction generators are typically small and connected into the distribution network, the responsibility for voltage control is normally kept with the respective electricity distribution business (induction loads are managed similarly). If the Authority were to propose more onerous requirements for induction generators, then we would request a transition period before the new requirements come into effect, to plan our investment accordingly.
3.	Q3. Do you consider there should be a capacity threshold (eg, a nominal net export or nameplate capacity 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.	We support further investigation by the Authority to clarify the requirements applicable to each generation technology, and the threshold to which it should apply
4.	Q4. 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?	We support a reactive power range of ±33% for new generation connecting to the local distribution network, as we expect that this generation will partially offset some of the reactive losses within the grid, when exporting power. From our experience, most distribution networks have limited capability to accept large amounts of reactive power transfer, due to their obligation to keep voltages within the range of 0.95-1.05 pu. Accordingly, a requirement to provide 50% reactive power export capability into distribution networks leads to oversizing inverters to provide a wider reactive range, or alternatively, additional costs to obtain a dispensation.
5.	Q5. Do you agree the Authority should be short listing the first voltage-related option to help addressing larger voltage deviations and network performance issues in New Zealand's power system address Issues 2 and 3? If you disagree, please explain why.	Adding voltage obligations to new generation with a point of connection to the transmission or MV distribution network is reasonable, as most modern generation technologies have this functionality included in their standard configuration. In our view, it would be reasonable to waive dispensation costs for existing generation installed prior to the introduction of updated requirements in the

		Code, provided an assessment is completed to determine the extent to which existing generation complies with the new obligations.
6.	Q6. What do you consider to be the main benefits and costs associated with the first voltage related option?	We expect the main benefits of the first voltage related option will be improved voltage profiles across the transmission and distribution networks, enabling a higher active power transfer capacity.
7.	Q7. Under the first voltage related option, what costs are likely to arise for the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network?	Compliance costs for generating stations under the 30 MW threshold will be large, if they are to be assessed and monitored in the same way as generating stations over the 30 MW threshold. For distribution connected generation, completion of detailed voltage tuning studies on a project-by-project basis will unnecessarily constrain engineering resource. Accordingly, we recommend the Authority further investigate how voltage control obligations would be assessed and monitored for generation under 30 MW.
8.	Q8. Under the first 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?	We expect that costs for energy storage systems to be similar to that of other generation technologies. However, energy storage systems (and all inverter-based generation) incur losses when idle, unless the inverter units are in a powered-down state. If any unit is required to be online and available solely for the purposes of providing voltage control, then we think it would be reasonable to reimburse the generator for its power consumption while providing this service. If the energy storage is online and is earning revenue from provision of another ancillary service, then we believe the cost of losses can be integrated into the offer for provision of these services. In other words, a generator or energy storage system should be obliged to comply with voltage regulation obligations whenever they are generating, charging, or dispatched for an ancillary service to the market.
9.	Q9. 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.	We support the general principle of the second voltage-related option, relating to management of the import and export of reactive power at a GXP. However, we believe the wording of the amendments needs further refinement, to reflect the following aspects: 1. Section 5.1, Clause (b) (ii) –The code should be more explicit about whether “Continuously operate in a manner that supports voltage and voltage stability on the transmission network” refers to being required to have the inverters online at all times, and if so, the cost of losses should be reimbursed (or not charged for in the first place). 2. Section 5.1, Clause (c) (ii) – it is much clearer to indicate reactive range as a percentage of maximum power transfer through the GXP transformer, i.e. +/- 33%. In this way, the distributor is compliant at times of low power transfer.

		3. Section 5.2 – A simpler approach would be to classify an energy storage system as a generator, such that it is subject to the same Part 8 requirements as a generator, whether generating, charging, or dispatched to provide ancillary services.
10.	Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	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 through each network. Co-ordination of reactive power flows should also help with minimising the additional reactive compensation equipment required.
11.	Q11. 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?	As per our response to Q8 – the same points apply for the management of reactive power. We expect that costs for energy storage systems to be similar to that of other generation technologies. However, energy storage systems (and all inverter-based generation) incur losses when idle, unless the inverter units are in a powered-down state. If any unit is required to be online and available solely for the purposes of providing voltage control, then we think it would be reasonable to reimburse the generator for its power consumption while providing this service. If the energy storage is online and is earning revenue from provision of another ancillary service, then we believe the cost of losses can be integrated into the offer for provision of these services. In other words, a generator or energy storage system should be obliged to comply with voltage regulation obligations whenever they are generating, charging, or dispatched for an ancillary service to the market.
12.	Q12. 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.	We strongly advocate for consistent fault ride through requirements across New Zealand and support the Electricity Authority initiative to update the Code to place fault ride through obligations on all new generators with capacity of less than 30 MW, to the extent the generation technology used has this capability. We acknowledge some generation technologies, such as induction generators, have minimal fault ride through capability. As induction generators are typically small and connected into the distribution network, the responsibility for fault ride through is normally kept with the respective electricity distribution business (induction loads are managed similarly). Should an existing generating unit be unable to comply, then we would expect a dispensation would be granted retrospectively, and for associated costs to be waived. .
13.	Q13. 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. Addressing larger	In our view, additional investigation is required to determine an appropriate fault ride through curve for generation connected to the distribution network.

	voltage deviations and network performance issues in New Zealand's power system protection considerations? Please give reasons for your answer.	We believe that alternative requirements should apply for synchronous and induction generators, as they are more susceptible to becoming unstable when operating at low voltages for extended durations, due to their physical characteristics. Accordingly, we recommend the following: 1) The proposed code amendments use wording that minimises the amount of dispensations needed to cover existing generation. 2) Where dispensations for existing generation are required, the dispensation costs will be waived, noting that the generator will be responsible for any costs to review the extent they comply with the proposed amendments.
14.	Q14. 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.	We advocate for all generation to comply with fault ride through requirements, to the extent the generation technology used has this capability. However, we believe that generation with capacity of less than 10 MW should not need to demonstrate compliance to the level of proof required for larger generation. We support further investigation by the Authority to clarify the requirements applicable to each generation technology, and the threshold to which it should apply.
15.	Q15. 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.	We support shortlisting for further investigation of the option to require more generating stations to comply with fault ride through obligations, subject to our responses given to Q12-Q14.
16.	Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	Encouraging a higher proportion of small generators to comply with fault ride through obligations will improve the stability and resiliency of New Zealand's power system.
17.	Q17. 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?	Additional costs to owners will be significant, if the owners are assessed and monitored in the same way as large generators. Many distribution networks rely on distributed generation tripping off during specific fault scenarios, to avoid inadvertent operation as an island. Revision of the fault ride through requirements for small generation may impact the operation of existing protection schemes, leading to costly upgrades. Accordingly, small synchronous and induction generators connected to the distribution network will likely require a dispensation, unless the applicable fault ride through obligations are further refined.
18.	Q18. Do you have any comments on the Authority's assessment of options to help address Issues 2, 3 and 4 identified in our 2023 Issues paper?	In addition to the options identified by the Authority, we advocate 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 pu (similar to the reduction in import capability between 0.95 to 0.9 pu). 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.

Table 3: The governance and management of harmonics in New Zealand's power system – Genesis Response

Question Number	Question	Genesis response
1.	Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If you disagree, please explain why.	Yes – The consultation paper prepared by the Electricity Authority accurately summarises New Zealand's key regulatory requirements for harmonics.
2.	Q2. Do you agree the Authority has identified the main challenges with the existing arrangements for the governance of harmonics? If there are any additional challenges, please set these out in your response	Yes – at present the NZ ECP 36 standard is most commonly used for assessment of compliance for "works", despite its scope being limited to assessment of emissions from a consumer's installation.
3.	Q3. Do you consider the existing regulatory framework for the governance of harmonics in New Zealand is compatible with the uptake of inverter-based resources? Please give reasons for your answer.	No – there is significant ambiguity around which standard applies to works, and there appears to be increasing scrutiny on harmonic emissions from generation, while there is less scrutiny of changing emissions from gradual changes to consumer and industrial load. More awareness is needed of the correlation between emissions from individual participants and the prevalence of harmonic issues, to fairly attribute costs according to the extent that each participant contributes. Additionally, there needs to be more clarity on the role and obligations of each participant, such as network owner/operator, asset owner, and equipment manufacturer.
4.	Q4. Do you have any feedback on the Authority's suggested way forward to help address the challenges with the existing arrangements for the governance of harmonics?	We generally agree with the adoption of the AS/NZS 61000 series, though we have reservations about adopting them in their entirety, as some sections are not prescriptive, and are open to interpretation. We agree with the adoption of planning and compatibility limits outlined in AS/NZS 61000.3.6:2012, Section 4.1. The limits specified in this section apply to LV, MV and HV networks, and we believe should be mandated as a requirement for all transmission and distribution nodes, unless a network company gets an exemption to apply different limits. Other sections AS/NZS 61000.3.6:2012 are informative, rather than prescriptive, and should not be referenced or interpreted as a requirement. Some assessment techniques outlined in the standard are overly complex to implement, considering that most stakeholders have limited resources available to devote to harmonic assessment and management activities. Other parts, such as the general summation law, unsuitable for assessing harmonic contributions from inverter-based generation as their validity depends largely on the control algorithms implemented by the equipment manufacturer.

5.	Q5. Do you have feedback on any of the elements of good industry practice relating to a framework for managing harmonics? This may include feedback relating to elements you consider are missing from the summary provided in section 5 of this paper.	We agree that the elements summarised in Section 5.3 represent good industry practice in relation to a framework for management of harmonics. The EEA Power Quality Guide 2024 provides reasonable coverage across most of these elements. However, we believe it would be more effective to substitute a harmonic allocation methodology for increased monitoring and continuous automated assessment strategy, as a single upfront assessment is incapable of forecasting how a generator's harmonic emissions will change over its lifetime. The allocation of individual emissions limits inadvertently promotes the installation of harmonic filtering equipment, well before harmonic voltages approach their planning limits. While the AS/NZS 61000.3.6 standard and the EEA Power Quality Guide allow for negotiation of allocated limits, this is rarely done in practice, typically because there are limited people available with sufficient expertise to guide each stakeholder through the negotiation process and there remains limited information about how the electricity network will change in the future. With respect to the timeframes for submission of harmonic data, we believe this information should be continuously streamed to a centralised database, which is then used to observe trends, assess the emissions from each participant, and forecast future changes in harmonic levels. This approach would reduce the administrative burden across all stakeholders by removing the need to manually share data, while also allowing compliance to be monitored more effectively. We believe a centralised harmonic database would be best hosted by the Electricity Authority (i.e. via the Electricity Market Information website), as it maintains objectivity, and prioritises the best outcomes for all stakeholders, including consumers.
6.	Q6. Do you agree with a 'whole of system' approach to allocating harmonics, so that any differences in harmonic allocation methodologies between electricity networks do not cause excessive harmonics? If you disagree, please explain why. The governance and management of harmonics in New Zealand's power system 34	A consistent harmonic management approach across New Zealand is essential to efficiently connect new generation and load, while also resolving power quality issues as they arise. As stated in our response to Q5, we believe that automated tools could be used to monitor harmonic levels, and trigger investment in harmonic mitigation solutions, at the time they are required. At the time that harmonic limits are approaching a threshold where they require mitigation, we believe that subsequent investment to assess, procure and implement the mitigation should be funded by the largest emitters, relative to the extent to which they contribute to the issue. In cases where

		there are no large emitters are identified (or where all participants contribute equally), then we believe these mitigation costs should be socialised. Power quality issues typically affect multiple stakeholders, so it is important that there are consistent management procedures across the electricity industry.
7.	Q7. Do you have any feedback on the suitability for New Zealand's power system of the harmonics standard NZECP 36:1993, or the AS/NZS 61000 series of harmonics standards?	As per our response for Q4. We generally agree with the adoption of the AS/NZS 61000 series, though we have reservations about adopting them in their entirety, as some sections are not prescriptive, and are open to interpretation. We agree with the adoption of planning and compatibility limits outlined in AS/NZS 61000.3.6:2012, Section 4.1. The limits specified in this section apply to LV, MV and HV networks, and we believe should be mandated as a requirement for all transmission and distribution nodes, unless a network company gets an exemption to apply different limits. Other sections AS/NZS 61000.3.6:2012 are informative, rather than prescriptive, and should not be referenced or interpreted as a requirement. Some assessment techniques outlined in the standard are overly complex to implement, considering that most stakeholders have limited resources available to devote to harmonic assessment and management activities. Other parts, such as the general summation law, unsuitable for assessing harmonic contributions from inverter-based generation as their validity depends largely on the control algorithms implemented by the equipment manufacturer.
8.	Q8. Do you have any feedback on the alternative approaches to limiting harmonic emissions, including alternative approaches you consider to be appropriate for New Zealand's electricity industry?	We support further investigation of an open access approach as we believe it will result in the best outcomes for New Zealand (for consumers, network owners and generators). Implementation of a centralised harmonic measurement database will be essential in ensuring this approach is fair to all stakeholders, while equipping network companies with the tools they need to ensure the electricity network operates as intended. While the costs to implement a centralised database may be significant, we expect these costs would be minimal compared to the savings obtained through minimising the need for additional harmonic filters.