To: Electricity Authority (the Authority)
FSR@ea.govt.nz

From: Electricity Engineers' Association of NZ

Date: 26 August 2024

Subject: EEA Submission in response to the Electricity Authority's suite of Consultation Papers that are part of the Future Security and Resilience (FSR) work program to Review the common quality requirements in the code.

The three papers include:

- **Paper 1:** An options paper that addresses frequency variability
- **Paper 2:** An options paper that addresses voltage deviations and network performance issues
- **Paper 3:** A discussion paper that describes our thinking on the governance and management of harmonics

OVERVIEW

The Electricity Engineers Association (EEA) of NZ welcomes the opportunity to provide feedback on The Electricity Authority's (the Authority) suite of Consultation Papers that are part of the Future Security and Resilience (FSR) work program to Review the common quality requirements in the code, which include:

- Paper 1: *"Addressing more frequency variability in New Zealand's power system"*
- Paper 2: *"Addressing larger voltage deviations and network performance issues in New Zealand's power system"*
- Paper 3: *"The governance and management of harmonics in New Zealand's power system"*

The EEA represents over 70 Corporate Members (companies) and 600 Individual Members across Aotearoa New Zealand from all engineering disciplines and sectors of the electricity supply industry (see Appendix A).

Collectively, we are the power industry's largest collaborative forum in Aotearoa New Zealand, provide clarity on complex engineering and technical issues, practical support and solutions, and market intelligence to support our members and other industry stakeholders to deliver good practice and policy outcomes.

The EEA supports the Authority's efforts in reviewing the common quality requirements outlined in Part 8 of the Electricity Industry Participation Code 2010 (Code), as part of the Future Security and Resilience (FSR) work programme. However, before finalising any decisions, the EEA recommends that the

Authority adopt a net benefit or 'whole of system' approach when evaluating the options outlined in the three papers to determine the best option for New Zealand as a whole. Without further analysis focused on net benefits, it is difficult to ascertain which option would provide the greatest economic value to New Zealand customers.

In terms of the three papers, the EEA consider that the Authority has prioritised the issues in the correct order of importance of being addressed, starting with frequency, followed by voltage, and then harmonics. This prioritisation is based on the potential impact of each factor if something goes wrong.

1. **Frequency:** Frequency is the most critical because it affects the entire grid. A significant deviation can lead to a grid-wide blackout if not corrected promptly, making it the most crucial issue to be solved.
2. **Voltage:** While voltage issues can cause problems like equipment damage or localised outages, they don't typically threaten the stability of the entire grid. They are more of a regional or localised concern.
3. **Harmonics:** Harmonic distortions and other power quality (PQ) issues, while increasingly common due to the proliferation of non-linear loads, tend to be more localized. They can cause issues like equipment malfunction or reduced efficiency, but these problems are usually isolated and do not threaten grid stability on a large scale.

This ranking is also reflected in the maturity of the options outlined in the papers, and therefore our response to the papers. In terms of the Frequency paper, the EEA concur with what has been outlined in the consultation paper and recommend that the Authority should investigate further, both:

- *Option 1:* Lower the 30 megawatt (MW) threshold for generating stations to be excluded by default from complying with the frequency-related asset owner performance obligations (AOPOs) and technical codes in Part 8 of the Code, and
- *Option 2:* Set a permitted maximum dead band beyond which a generating station must contribute to frequency keeping and instantaneous reserve.

This paper also asked the question regarding the appropriate size of distributed generation that should assist with frequency support. We believe that a critical feature to prioritise is the capability for frequency and voltage disturbance ride through. This requirement should extend to all distributed generation, including domestic rooftop solar, to prevent the disconnection of numerous smaller systems, which could exacerbate an event.

In terms of the other two papers on voltage and harmonics, the EEA is providing a more detailed response to the questions posed in these papers which can be found below.

EEA is keen to continue our collaboration with the Authority, industry, and other stakeholders regarding the review of the system operation requirements for New Zealand.

Consultation Paper 2 – Addressing larger voltage deviations and network performance issues in New Zealand's power system

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?

Yes. The EEA anticipate that the EDBs will likely impose voltage support obligations on generators and energy storage systems (when discharging), particularly for systems 5MW and above. We have been made aware that EDBs will be looking more closely at ensuring compliance with fault ride-through and voltage support requirements, and have requested that the EEA look at including this requirement in our proposed Common Technical Connection Guidelines for DER.

The majority of EDBs already mandate that high voltage installation owners are required to coordinate with them on connection, operation, and modifications of their installations. The EEA also recommends that the EDBs adhere to our Power Quality Guideline. We have also identified that compliance to AS/NZ3000 for HV electrical installations and compliance with AS/NZS 4777.2:2020 for inverter requirements be included in our proposed suite of common connection guidelines.

However, we note that there are currently issues in identifying smaller distributed generators as they are not currently tracked or registered under the Code. While 66kV generators must comply with the Code, smaller generators are not subject to the same requirements.

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 (e.g., 33kV)?

The EEA agree that generating stations and energy storage systems connected to local distribution networks at the GXP voltage should be required to support voltage. However, this brings up important questions about voltage control versus the VAr Dispatch Schedule System, including who should be responsible for maintaining uniform voltage and covering the associated costs.

Addressing the issue of voltage support in local distribution networks is indeed crucial, particularly as the energy landscape evolves with increasing integration of distributed energy resources (DERs) and smart technologies. Any solution needs to account for the unique characteristics of local distribution networks, such as variations in load, generation, and grid topology, to ensure that voltage support is both effective and efficient. Key Considerations for a solution include:

- Localised Assessment: i.e. Network topology and load and generation profiles
- Assignment of Responsibilities: i.e. The role of DERs, the system operator, EDBs and the consumer
- Cost Distribution: i.e. fair cost allocations and incentive structures
- Regulatory and Market Frameworks: i.e. Effective regulation, setting standards and market Mechanisms.

This issue highlights the need for a broader, systemic discussion on how voltage stability is maintained as the energy system becomes more decentralised and digitalised. Ensuring that responsibilities and costs are appropriately distributed will be key to maintaining a stable and efficient energy system.

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?

While the EEA acknowledges the importance of establishing a capacity threshold, we believe it should be tailored to the specific characteristics of each distribution network rather than applying a fixed value across the board. A one-size-fits-all threshold may not accurately account for the unique impact of new generators on a network and could unintentionally incentivise installations just below the minimum capacity to sidestep regulatory requirements.

We therefore recommend that all entities connecting at certain voltage levels (e.g., 11kV, 33kV, 66kV) be required to support voltage regulation, irrespective of their capacity. By avoiding rigid limits, the Authority can create a more adaptable and future-proof regulatory framework.

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?

Pros of Requiring a ±33% Reactive Power Range:

- **Consistency and Standardisation:** 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.
- **Enhanced Voltage Support:** A reactive power range of ±33% provides more flexibility for voltage control, which can enhance the grid's ability to manage voltage levels, particularly in areas with high penetration of renewable energy sources. However, voltage management using reactive power can have some unintended consequences. There will need to be limitations on how much reactive power should be used as reactive power does consume network capacity. Powerco is using a guideline of up to 33% MVArs. (i.e.: MVArs is limited to 33% of the MWs). Its equivalent to 0.95pf, which roughly equates to 10% extra thermal load. Further work is required on how to define reasonable deadband, and outside the deadband there would need to be a voltage droops. The volt-var mode can create unexpected upstream volt drops where X/R ratios vary along the supply route.
- **Improved Grid Resilience:** With a more stringent reactive power range, the grid could become more resilient to fluctuations and disturbances, contributing to overall system reliability.

Cons of Requiring a ±33% Reactive Power Range:

- **Technical Challenges:** Many renewable generating stations, particularly inverter-based resources like solar and wind, may find it difficult to achieve this reactive power range. These technologies are often limited in their ability to provide reactive power and meeting a ±33% requirement may necessitate significant and costly upgrades.
- **Economic Impacts:** For renewable distributed energy projects, especially smaller ones, the cost of compliance could be prohibitively high. This could discourage investment in these projects, slowing down the transition to a more sustainable energy system.
- **Limited Headroom for Solar Installations:** 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.

- **Compatibility Issues with Harmonic Filters:** 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.

While a standardised reactive power range could improve grid stability and resilience, the proposed ±33% range might be too demanding for many renewable energy sources. More research or consideration of a more moderate approach could balance the need for voltage support with the practical and economic limitations of various generating technologies, ensuring that the development of smaller, distributed renewable energy projects is not discouraged.

Q5: Do you agree the Authority should be short listing the first voltage-related option to help address Issues 2 and 3?

While the EEA consider that the Authority should consider a combination of all three Options, we agree that the Authority could prioritise the first voltage-related option to address Issues 2 and 3.

While we support placing voltage support obligations on generators, particularly those 5MW and above, we have concerns about the practicality and fairness of implementing these obligations on existing distributed generation. We also stress the importance of considering the varied nature of local distribution networks and the need for a comprehensive approach to voltage support that doesn't rely solely on fixed capacity thresholds.

Q6: What do you consider to be the main benefits and costs associated with the first voltage-related option?

EEA provides no comment on this question.

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?

While the EEA cannot provide specific cost estimates, we anticipate that under the first voltage-related option, the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network could face several potential costs, including:

- Retrofitting Costs: These could include expenses related to upgrading or modifying existing equipment to meet new voltage support obligations. This might involve the installation of new hardware, software upgrades, or adjustments to control systems to ensure compliance with the new requirements.
- Compliance and Certification Costs: Owners may need to undergo new compliance checks or obtain certifications to demonstrate that their systems meet the new standards. This could involve costs for inspections, testing, and documentation.
- Operational Costs: There could be ongoing operational expenses associated with maintaining the voltage support capabilities, such as increased wear and tear on equipment, higher energy consumption, or the need for more frequent maintenance.
- Technical Consultation and Engineering Costs: Owners might need to hire consultants or engineers to assess their systems, design the necessary upgrades, and ensure proper implementation. These costs could be significant, especially for complex or large-scale systems.
- Downtime and Lost Revenue: During the period when the retrofitting or adjustments are being made, there could be downtime for the generating stations or energy storage systems. This could lead to lost revenue, particularly for systems that rely on consistent operation for income.

While exact cost estimates are not available, these potential costs could be substantial, depending on the scope and complexity of the required retrofitting and the specific characteristics of the systems involved.

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?

EEA provides no comment on this question.

Q9: Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3?

The EEA agree that the Authority should shortlist the second voltage-related option, but we have identified several issues that would need to be addressed before it was considered for implementation. These include:

- Power Quality Management: If implemented as currently proposed, this option would require distributors to control, manage, and set power quality limits within their own networks. We would recommend that they align using a standardised methodology such as the EEA Power Quality Guideline.

- Implementation Complexity: We have concerns on how this option could be implemented in practice, as if not thought through could lead to unexpected and unnecessary complexity into the process.
- Engaging Distributed Generators: Ensuring that the System Operator engages with distributed generators to ensure that they provide GXP voltage support.
- Capability Concerns: Implementing this option would require capabilities that EDBS currently do not have and would be hard to establish and maintain, especially for 27 EDBs.
- Coordination of Reactive Power Flows: We have concerns on how the amendment to Part 8, would function in practice as it would require the System Operator and the EDBs to coordinate reactive power flows at GXPs in either direction. Whilst possible, work will be needed regarding how this could be implemented (i.e. establishment of dynamic operating envelopes, DSO, new market mechanisms etc….).
- Schedule 12.6 Amendment: The proposed amendment to Schedule 12.6 requires EDB voltage support assets at a GXP to be capable of operating within a power factor range of 0.95 lagging to 0.95 leading. However, the Authority needs to recognise that not all EDB voltage support assets are currently located at a GXP.

Q10: What do you consider to be the main benefits and costs associated with the second voltage-related option?

The EEA considers that the main benefits of the second voltage-related option include:

- **Improved Voltage Stability:** Enhances the reliability and stability of the voltage levels within the electricity network, reducing the risk of outages or equipment damage.
- **Better Coordination:** Facilitates more effective coordination between the System Operator and distributors, potentially leading to more efficient system operations and improved grid management.

The main costs would include:

- **Investment in Distributed Energy Resources Management Systems (DERMS):** EDBs would need to implement a DERMS for real-time visibility and forecasting, which could duplicate some functionalities of the System Operator. This replication could potentially be more inefficient and costly than developing a dedicated Distribution System Operator (DSO) function.

- **Substantial Investment in New Tools and Processes:** EDBs would need to invest significantly in new tools, processes, and methods to manage voltage support effectively across their networks.
- **Ongoing Operational Costs:** There would be ongoing costs associated with the increased complexity of managing voltage support and ensuring proper coordination with the System Operator.

These factors will require thorough evaluation to assess whether the benefits surpass the costs, ensuring that the option provides net value to the electricity system and its consumers.

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?

EEA provides no comment on this question.

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?

The EEA consider that it is likely that EDBs would establish fault ride through obligations on some or all <30MW generating stations, even in the absence of a Code requirement. EDBs have a strong incentive to ensure system stability and reliability, and fault ride through capabilities are essential for maintaining grid resilience during disturbances.

Without a Code requirement, while EDBs can request compliance, their ability to enforce these obligations on connected generating stations would indeed be limited. 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.

The EEA consider that implementing a clear Code requirement for all <30MW generating stations would standardise these obligations across the industry. This would not only provide a legal basis for enforcement but also ensure that all generating stations, down to 10MW, have the necessary capabilities to ride through faults without excessive costs, especially given that standard inverters already meet these requirements. Consistency in requirements is key to maintaining a stable and reliable energy system, and a Code requirement would certainly aid in achieving that goal.

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 protection considerations?

The EEA agree that the Authority should consider including fault ride-through (FRT) curves in the Code for generating stations connected to a local distribution network, however, it is important to ensure that the requirements are suitable for distribution networks and do not impose unnecessary burdens on smaller generators.

Some key points include:

- Appropriateness of FRT Curves: We agree that it is appropriate to include fault ride-through curves in the Code for generating stations connected to local distribution networks, especially at a nominal voltage equal to the GXP voltage. This inclusion can provide clarity and consistency for all stakeholders involved.
- Complexities and Compliance: While larger generators, such as those operating at 66kV, should comply with the Code curve, there is an acknowledgment that smaller generating stations may present more challenges in terms of compliance and management. This suggests the need for tailored approaches for different sizes and types of generating stations.
- Network Protection Considerations: It is important to consider network protection in the context of distribution networks. Traditionally, protection considerations have focused more on transmission networks, but as DER and embedded generation become more prevalent, there is a need for robust local protection requirements.
- Clarity and Consistency: Including these curves in the Code could help standardise expectations and requirements across the board. However, it's essential to ensure that the requirements are suitable for distribution networks and do not impose unnecessary burdens on smaller generators.

However, if the Authority determines through this consultation process that it is not appropriate to include fault ride-through (FRT) curves directly in the Code, the EEA suggests incorporating them into our proposed technical guides and/or our power quality guide. If this approach is preferred, we would request that the Authority refer to these guides.

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?

The idea of setting a threshold for generating stations connected to distribution networks to ride through faults is indeed a complex one. There are several factors to consider, including both voltage and capacity, with the key points including:

- **Voltage vs. Capacity Threshold:** Voltage: As you mentioned, a threshold based on connection voltage could be more relevant than one based on capacity. Voltage levels directly relate to the type and size of network a generating station connects to, as well as the expected fault tolerance and stability of that network. Higher voltage levels typically correlate with a higher level of network robustness and fault tolerance requirements.
- **Capacity:** While capacity (such as nameplate capacity or nominal net export of 5MW or 10MW) is important, it is not the only factor determining the impact of a generation unit on the network's stability. Smaller installations on low-voltage networks might not need the same fault ride-through capabilities as larger installations connected to higher voltage networks. However, capacity thresholds can help prevent grid instability caused by numerous small installations disconnecting simultaneously during faults.
- **Economic Considerations:** Connecting small capacity installations to high-voltage networks is typically uneconomic due to the costs associated with transformers, switchgear, and other infrastructure. This economic factor naturally limits where smaller generation units are installed and suggests that voltage-based thresholds could more effectively align with practical realities.
- **Regulatory Future-Proofing:** Setting thresholds that are too rigid or based solely on current technology and market conditions can lead to frequent revisions of the regulatory code, as technological advancements or shifts in the energy market landscape may render them obsolete. An approach that considers both voltage and capacity, with a focus on adaptability to future technologies and grid dynamics, could create more robust and future-proof regulations. Establishing a more flexible approach could help avoid repeating past mistakes, such as implementing minimum numbers that soon become outdated.
- **Holistic Approach:** A balanced regulatory framework might involve a combination of voltage and capacity thresholds, where fault ride-through requirements are more stringent at higher voltages and capacities. This dual approach allows for greater precision in regulatory measures, ensuring network stability while accommodating various generation types and sizes.

- **System Operator's perspective:** It is worth questioning the actual risk posed by 5MW and 10MW generating stations if they are non-compliant. Is there a genuine risk of network failure in such cases? During disturbances, load typically decreases, and DER are not yet significant enough to cause major issues. Moreover, in the South Island, DER generally already complies with ride-through obligations.

Implementing both a voltage and capacity threshold could simplify compliance for smaller generators, but it might overlook important contributors to system stability. On the other hand, not having a threshold ensures all generators contribute to system stability but could place an unnecessary burden on very small generators. We believe that a voltage-based threshold would be more appropriate, ensuring that generators connected at higher voltages possess ride-through capabilities regardless of their capacity.

Q15: Do you agree the Authority should be short listing for further investigation the third voltage-related option to help address Issue 4?

The EEA agrees that the Authority should short list the third voltage-related option to address option 4. This will allow for a more focused investigation into its potential benefits and challenges and will allow the Authority to explore all viable options to ensure comprehensive solutions are considered.

Q16: What do you consider to be the main benefits and costs associated with the third voltage-related option?

EEA provides no comment on this question.

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?

EEA provides no comment on this question.

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?

The EEA believe the Authority's assessment of options to address Issues 2, 3, and 4 is reasonable. We appreciate the comprehensive approach taken to evaluate the various challenges and potential solutions. The options presented seem well-aligned with the needs of the market and the goals of enhancing efficiency, reliability, and consumer engagement in the energy sector.

Consultation Paper 3 – Addressing larger voltage deviations and network performance issues in New Zealand's power system

Q1: Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics?

The EEA appreciates the Authority's effort in summarizing New Zealand's existing regulatory requirements for harmonics. However, we believe that while the summary provides a foundational overview, there are critical aspects that warrant further investigation and attention.

- NZECP 36:1993 Limitations: The EEA considers that NZECP 36:1993, is outdated and should be phased out. This standard, based on harmonic limits that were established in 1967, and was written based on the technology that was current in 1970s and 80s. The switching methodology at that time created only integer harmonics, and the 50^{th} harmonic was thought to be a very high (2.5kHz). Technology has moved on. Transistor switching technology is now able to run well above 100 kHz. While we still need to manage harmonics, we now also need to consider inter-harmonics and high frequency (supra-harmonics) too. ECP36.does not adequately address the needs of today's rapidly evolving electrical environment and are therefore no longer fit for purpose. The continued application of this standard by Transpower, despite its divergence from broader industry practices, highlights a disconnect that should be addressed to ensure regulatory relevance. Lessons could be learned from other jurisdictions in this area.
- IEEE 519 Standard Concerns: We recognize the comprehensiveness of the IEEE 519 standard; however, its specificity might lead to rigidity, particularly when considering future technological advancements such as hydrogen electrolysers. This suggests the necessity for guidelines that are not only robust but also flexible enough to accommodate emerging technologies without being constrained by outdated parameters.
- AS/NZS 61000 and International Alignment: The inclusion of AS/NZS 61000 in the summary aligns with internationally recognised standards, which is crucial for maintaining consistency and interoperability in power quality management. The IEC 61000 series has also considered the ranges for current technologies and is more appropriate than using NZECP 36:1993. However, while international alignment is important, it is equally vital that these standards are adapted to reflect New Zealand's unique electrical landscape and challenges.

- **The EEA Power Quality Guide:** The EEA strongly advocates for the adoption of its EEA Power Quality Guide (2024) as the primary reference for managing harmonics in New Zealand. These guidelines are designed to be more adaptable and forward-looking compared to older standards. They were developed to address emerging challenges such as supraharmonics, intraharmonics and high-frequency harmonics, and consider the complex interactions between modern electrical devices. Regular updates ensure these guidelines remain relevant and aligned with the latest research, particularly in the context of European studies on high-frequency harmonics. This makes them a dynamic and up-to-date resource for effective power quality management.

In conclusion, while the Authority's summary covers the existing regulatory framework, the EEA believes there is a pressing need for more modern, flexible, and forward-looking guidelines. The EEA Power Quality Guide (2024) is currently better equipped to address the complexities of todays and tomorrow’s electrical landscape and can be easily updated in contrast to the code, ensuring that New Zealand remains at the forefront of power quality management.

Q2. Do you agree the Authority has identified the main challenges with the existing arrangements for the governance of harmonics?

The EEA acknowledges that the Authority has successfully identified the primary challenges within the current governance framework for harmonics. However, we believe that the current standards and regulations lack the necessary flexibility to accommodate future technological advancements. We therefore wish to underscore and elaborate on several key areas that require further consideration:

- **Technical Complexities:** The existing governance framework is increasingly challenged by the complexity of managing harmonics in modern power systems. With the growing integration of DER, DG and advanced technologies, technical demands on the system have escalated. A notable issue is the generation of reactive power by harmonic filters, which can lead to unintended consequences such as voltage regulation challenges, increased system losses, and potential overcompensation of power factor. These issues underscore the need for a governance approach that is attuned to the intricate technical realities of contemporary networks.
- **Outdated Standards:** EEA concur with the Authority’s observation that many existing standards and regulations are outdated and no longer fit for purpose in today’s rapidly evolving power landscape. These standards were developed under different technological conditions and are

not equipped to address the complexities of modern power systems effectively. There is an urgent need to update these standards to reflect current and emerging technological realities.

- Regulatory Discrepancies: We are concerned about the inconsistency in the regulatory environment, particularly the continued use of NZECP 36:1993 by Transpower, which creates a divergence from industry-wide practices. This lack of alignment across the sector could result in inefficiencies in harmonics management, highlighting the need for a more unified and consistent regulatory approach.

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?

The EEA does not think that the current existing regulatory framework for the governance of harmonics in New Zealand is compatible with the uptake of inverter-based resources.

As stated previously, the EEA consider that the continued reliance on NZECP 36:1993, which is grounded in harmonic limits from as far back as 1967, is particularly concerning. This standard does not adequately address the needs of modern inverter-based resources, including power converters and the emerging issue of supraharmonics. As electric vehicle (EV) charging and smart grids become more prevalent, these supraharmonics, which fall outside the traditional power quality frequency range, could have significant implications for the future stability and reliability of the electrical grid.

It is essential that the Energy Authority (EA) broadens its approach to the governance of harmonics, considering not only the ever-increasing uptake of inverter-based resources but also the wider array of emerging technologies that are reshaping the energy landscape. Some of these new technologies are introducing significant harmonic currents on the grid-side that are not currently addressed by existing regulations. Therefore, the EEA would recommend that the support the adoption of more flexible guidelines, such as the EEA Power Quality Guidelines, which can be readily updated to accommodate new technologies as they become established. This adaptability is crucial to ensuring that our regulatory framework remains relevant and effective in managing harmonics in an increasingly complex and evolving energy sector.

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?

From the perspective of the Electricity Engineers Association (EEA), we appreciate the Authority's efforts to address the challenges associated with the current governance of harmonics. While the

AS/NZS 61000 standards, derived from the globally recognized IEC 61000, provide a robust foundation, we believe that the EEA Power Quality Guidelines offer a more tailored and flexible approach for New Zealand's unique electricity system. These guidelines, while rooted in the AS/NZS 61000 standards, are specifically designed to meet the needs of our local industry and should be considered the default for harmonics governance.

Though adopting the AS/NZS 61000 standards may be necessary in certain instances, we want to highlight a potential conflict with Transpower's operating requirements, particularly for voltages exceeding 220kV. The current standards do not sufficiently address these higher voltage levels, necessitating the development of specialized engineering solutions by Transpower. Therefore, any new governance framework must comprehensively account for all voltage levels within New Zealand's electricity system to ensure that compliance and adoption are feasible across the sector.

We agree with the Authority's observation in clause 4.23 regarding the benefits of standardising harmonic limitations, management, and allocation across all market participants. Consistency in how solar installations and other DER are managed across different EDB networks is essential for effective and fair harmonics management throughout New Zealand.

Furthermore, while we support the Authority's stance in clause 4.25, we recommend that the Authority consider going a step further. We advocate for the use of guidelines as the preferred method for regulating and managing harmonics. This approach would provide the necessary flexibility to adapt to future technological advancements and evolving network conditions, ensuring that New Zealand's electricity system remains resilient and responsive to change.

Q5. Do you have feedback on any of the elements of good industry practice relating to a framework for managing harmonics?

From an EEA perspective, we recognise that the high-level framework for managing harmonics is robust, yet we have identified several areas where refinements could further enhance its effectiveness.

- Principles for the Management of Harmonics

  While flexibility is valuable, the EEA strongly advocates for a nationwide, consistent set of requirements, as exemplified by the EEA Power Quality Guidelines. Such consistency ensures a uniform approach across New Zealand, which is crucial for maintaining a level playing field while still allowing for adaptability in response to technological advancements. We believe that a standardised approach to basic requirements, complemented by flexible implementation guidelines, provides an optimal balance between standardisation and the ability to adapt to changing conditions.

We also support the implementation of a blanket limit above the 50^{th} harmonic to address issues that could affect earthing system neutrals and overall performance. There is currently a regulatory gap concerning frequencies between 2500Hz and telecommunication bands, which should be addressed. Additionally, the EEA underscores the need to consider that power quality issues are increasingly emerging at higher harmonic levels, reflecting the evolution of modern power systems. An example of this is the flickering of LED lighting, a known issue caused by higher harmonic levels.

- Planning and Compatibility Levels

The EEA agrees that the NZECP harmonic levels are outdated. Our preference is for the adoption and enforcement of the EEA Power Quality Guidelines, which reflect current best practices and technological realities.

- Voltage Levels

The EEA have noted inconsistencies between the term 'medium voltage' as used in the framework and other New Zealand standards and regulations. To avoid confusion, we suggest either using numerical classifications (e.g., 1, 2, 3) or aligning with the terminology used in other standards (e.g., low voltage as ≤ 1kV, high voltage as 1kV < U n ≤ 230kV).

- Measurement of Harmonics

The EEA expresses concern about the proposal to publish background harmonic data. We recommend that the Authority thoroughly evaluates the value and practicality of this approach. Specific areas that require clarification include expected measurement locations, data requirements, and timeframes. It is important to note that harmonic levels at Grid Exit Points (GXPs) can vary annually, and network reconfigurations by Transpower can significantly impact these levels. Clear guidelines on measurement and publication requirements should be developed, and if necessary, these should be integrated into existing Information Disclosure requirements. Furthermore, we stress the importance of monitoring harmonic levels both before and after the commissioning of new equipment.

- Roles and Responsibilities

The EEA request clarification on clause 5.23(d) of the Authority’s proposal regarding what defines a ‘key site’? Does this refer to a zone substation, GXP, or a solar farm? Additionally, we seek clarity on whether the requirement in clause 5.23 is related to the publishing of background harmonic data as stated in clause 5.21.

- Timeframes for Managing Harmonics

  The EEA is cautious about the inclusion of mandatory timeframes for managing harmonics within the Code or the adoption of timeframes from other standards, as we consider that further work is required before considering mandating rigid timeframes. While consistency across Electricity Distribution Businesses (EDBs) is desirable, we believe that the Authority could investigate some of the current frameworks being used by EDBs to ensure that any final compliance mechanisms are fit for purpose.

- Methodology for Allocating Harmonics

  The EEA acknowledges that developing a methodology for allocating harmonics is complex, and we encourage further industry-wide discussions to explore potential solutions.

By addressing these concerns, we believe the framework can be further strengthened to better manage harmonics across New Zealand's power system.

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?

The EEA support the adoption of a 'whole of system' approach to allocating harmonics, as it aligns with our commitment to fostering a level playing field across the electricity sector. This approach is key to ensuring that differences in harmonic allocation methodologies between electricity networks do not result in excessive harmonics, which can compromise system reliability and performance.

We recognize the potential benefits of this approach and believe it can enhance the overall management of harmonics. However, we would like to offer some constructive suggestions for its implementation. For instance, while Transpower currently allows for generation connections, we see an opportunity for improvement in fully considering local EDB constraints and ensuring transparency for whole system needs. We concur with the Authority, particularly in clause 5.35, that a truly effective 'whole of system' approach should promote clear and consistent communication between Transpower, EDBs, and other industry participants. This will help ensure that both local constraints and system-wide needs are properly accounted for, reducing inconsistencies and challenges in harmonic management across different parts of the network.

To facilitate the success of this approach, we encourage the Authority to provide clear guidance on key concepts such as 'harmonic headroom' and 'harmonic allocation.' These are complex and critical issues that require careful consideration and a consensus within the industry to ensure fair and effective implementation.

Additionally, we suggest that the Authority present concrete evidence of any damage caused by higher level harmonics. Understanding the actual impacts of harmonics on the system is essential in developing a balanced approach to harmonic mitigation that considers both costs and benefits. This balance should inform any allocation methodologies or requirements for harmonic management.

Finally, we believe that any ‘whole of system’ approach should be designed with flexibility in mind, allowing for future technological advancements that may influence harmonic generation or mitigation. By doing so, we can ensure that the framework remains relevant and effective as the energy landscape evolves.

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?

The EEA acknowledges that the NZECP 36:1993 standard is significantly outdated and does not adequately address the current and emerging demands of New Zealand's power system. Originating from harmonic limits set in 1967, this standard fails to consider advancements in modern power system technologies, particularly those involving inverter-based resources and other innovative technologies.

While the AS/NZS 61000 series provides a more contemporary framework for managing harmonics, we believe it lacks the necessary flexibility to fully cater to New Zealand's unique and evolving energy requirements.

We strongly advocate for the adoption of the EEA Power Quality Guidelines, or equivalent as a better alternative to both NZECP 36:1993 and AS/NZS 61000 standards. A guideline offer enhanced adaptability in addressing harmonic issues and are better equipped to evolve alongside future technological developments within the country's energy sector.

Considering the rapid advancements and uncertainties in technologies such as renewable energy integration, electric vehicle adoption, electrification and smart grid systems it is imperative that our approach to harmonic management remains flexible. Relying on adaptable guidelines rather than rigid, compliance-based regulations will better position New Zealand to meet and navigate these forthcoming challenges effectively.

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?

From an EEA perspective, a balanced approach to limiting harmonic emissions is essential for ensuring both network reliability and fostering innovation. Therefore, the establishment of an approach that offers the flexibility needed to adapt to emerging technologies and evolving network conditions while establishing incentives for responsible harmonic management is essential for the electricity industry in New Zealand.

By not imposing rigid, blanket restrictions, it will encourage innovation and allows for a more dynamic response to the challenges posed by harmonic emissions. However, this would need to be undertaken in a way that ensure that any financial mechanisms associated with this approach ensure that network quality is maintained, protecting both consumers and the grid.

Moreover, this approach is consistent with our recommendation to utilise guidelines such as the EEA Power Quality Guide, which would provide a more adaptive framework compared to fixed regulatory mandates. The ability to update and refine harmonic management strategies in line with technological advancements is crucial in our rapidly evolving energy landscape, where agility and foresight are key.

We also hold a strong position against requiring connecting parties to act as net absorbers of harmonic emissions. This requirement is impractical and could hinder progress by placing undue burdens on certain stakeholders. Instead, our focus should remain on creating a balanced and flexible system that promotes responsible management of harmonic emissions without stifling innovation.

[redacted]

[redacted]

Appendix A

Introducing EEA

Founded in 1927 the EEA is the national organisation for engineering, technical and health and safety matters within the New Zealand Electricity Supply Industry (ESI).

Our members include over 70 Corporate Members (companies) and 600 Individual Members from all engineering disciplines and sectors of the electricity supply industry including generation, electricity networks (transmission and distribution), contractors (operation/maintenance), engineering consultancies and equipment suppliers.

The EEA works collaboratively with industry, government, and other stakeholders to provide expertise, advice, and holds or contributes to significant bodies of knowledge on engineering/ technical and safety issues relating to the electricity supply industry in New Zealand. All EEA guides and publications are publicly available.

A key focus of our work is enabling engineering and technology understanding and solutions to support decarbonisation and ensure the safe, reliable, and secure delivery of electricity to our communities.

Our functions include:

- Production and ongoing stewardship of 'bodies of knowledge' including engineering, technical, asset management and safety publications (e.g., guides, Standards, industry reports, and links to relevant legislation and international information).
- Representing the New Zealand electricity supply industry in national and international Standard development and facilitation of benchmarking in safety, technology, and asset management (e.g., IEC, AS/NZS, NZS Standards).
- Providing and supporting engineering and technical professional development and competency for our engineers/technical staff.
- Providing a web-based knowledge hub on safety, engineering, asset management, emerging technology and professional development including information services, notifications, newsletters, guidelines and support documents, events, and infrastructure engineering careers information.

The EEA is currently a partner with EECA and industry in the delivery of the FlexTalk programme which aims to maximise participation in flexibility services through the adoption of a common communication protocol. It also has membership on the Electricity Authorities Common Quality Technical Group (CQTG) and has observer status on the Authorities Network Connection Technical Group (NCTG).