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Electricity Authority
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Tēnā koutou

Consultation - Future Security and Resilience – Review of common quality requirements in the Code

WEL Networks (WEL) appreciates the opportunity to provide feedback on the Electricity Authority's (the Authority) Consultation - Review of common quality requirements in the Code (the Consultation).

WEL is New Zealand's sixth largest electricity distribution company and is 100% owned by our community through our sole shareholder WEL Energy Trust. Our guiding purpose is to enable our communities to thrive, and we work to ensure that our customers have access to reliable, affordable, and environmentally sustainable energy.

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

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

OPTION 1 - WEL Networks does not support Option 1. Voltage related performance obligations for distribution connected generation and energy storage systems should be set by distributors according to the needs of their network(s). Therefore, voltage related obligations for distributed generation (DG) and energy sources should not be prescribed within the Code.

The consultation paper suggests that, should Option 1 be adopted, the System Operator intends to issue reactive power dispatch instructions directly to DG and distributed energy resources (DER) once voltage support obligations apply to DG and DER. This is consistent with WEL Networks' past discussions with the System Operator on the topic. If this is the case, then further issues need to be resolved:

- Asset safety if the System Operator dispatch instructions result in asset overloading;
- Impact on distribution network reliability due to outages from DG and DER following System Operator dispatch instructions;
- Risk of distribution voltages going outside legislative limits from DG and DER following System Operator dispatch instructions; and
- Which party is financially and legally liable should these events occur.

It is increasingly likely that distributors will be actively managing congestion caused by DER on their networks. This will likely be achieved by dispatching real and reactive power of DER to manage distribution asset loading and distribution network voltage. Having a third party (System Operator) also issuing dispatch instructions to the same DER will cause problems with congestion management. It is recommended that a hierarchy of dispatch is established with the needs of the distribution network (where the DG and DER are embedded) taking priority before the needs of the transmission network.

As the System Operator does not have visibility of distribution asset loading, voltages, or distribution network configuration, it is inappropriate for the System Operator to be issuing reactive power dispatch instructions directly to DG and DER. Otherwise, there is a risk of asset damage, interruptions to supply, and the distributor not meeting its legislated obligations in regard to voltage.

Another issue that would need to be addressed is the question of liability with regard to damages or breaches of law/regulation resulting from System Operator reactive power dispatch instructions to DG or DER. WEL suggests that if 'Option 1' were adopted, redress must be aligned to the party issuing reactive power dispatch instructions (i.e. the System Operator).

Distributors should define the required degree of visibility of the operating status of DER and active power and reactive power output in the Connection and Operating Standard. An aggregate of DG and DER active and reactive power output, at the grid exit point (GXP) level, may be able to be provided by the distributor to the System Operator, if required.

OPTION 2 - WEL supports 'Option 2'. Issues 2 and 3 are better managed by the distributors in terms of distribution networks, and the system operator in terms of the transmission network. The appropriate location for co-ordination is at the GXP.

WEL supports fault ride through requirements on certain DG and DER as the issue relates to faults on transmission assets potentially resulting in the disconnection of large amounts of DG and DER. WEL Networks believes a 20 MW threshold is appropriate.

The following table is based on Figure 9-1 in the System Operator report on frequency issues:

Size of DG	Number of DG	Estimated total amount of generation	Percentage
20 MW to 30 MW	9	225 MW	40%
10 MW to 20 MW	13	195 MW	35%
5 MW to 10 MW	9	67.5 MW	12%
0 MW to 5 MW	30	75 MW	13%
		562.5 MW	**100%**

Table 1 – Summary of System Operator report on frequency issues

Table 1 shows that a 20 MW threshold will cover 40% of DG. Assuming 20% of the remaining DG trips, the amount of generation lost is around 67 MW (assuming all DG is at maximum output). This is less than the amount of instantaneous reserves generally procured by the System Operator.

The fault ride through requirements should take into account the probability of certain faults. The severest faults (e.g. a bolted fault on a major 220 kV bus) are not contingent events or even extended contingent events. WEL suggests that fault ride through requirements should be based on faults that may be expected to occur frequently enough to qualify as contingent events.

WEL suggests that fault ride through compliance during faults should be assessed, taking distribution protection requirements into account.

The issue of how a Virtual Power Plant (VPP) might be obligated to meet common quality asset owner performance obligations (AOPOs) is complicated. The costs of the owner of a VPP of complying with the AOPOs will vary significantly depending on the composition of the plant making up the VPP. A set of identical 1 MW DG units may be straight forward, but a VPP comprised of many generating units of different size and with different design and manufacture will face much higher costs.

Energy Storage Systems (ESS) potentially face additional difficulties when supporting voltage while charging. When charging, ESS often face distributor or Transpower requirements to maintain a minimum power factor at certain times. The requirement to manage power factor within certain limits will restrict the amount of voltage support that can be provided at the same time. It is suggested that distributors, and Transpower, review minimum power factor requirements.

We have provided more fulsome answers to the questions posed in the consultation paper in Appendix A.

Paper 3: The governance and management of harmonics in New Zealand's power system

WEL believes that more work needs to be done understanding the cost-benefit trade-offs implicit in a harmonics management framework. Figure 1[1] indicates that, although the costs of poor power quality (PQ) are high, the costs related to harmonics are only a very small proportion of PQ costs. Additionally, the survey data analysed in the paper is close to 20 years old, as technology has advanced considerably in this time, it may not be appropriate to draw conclusions from it.

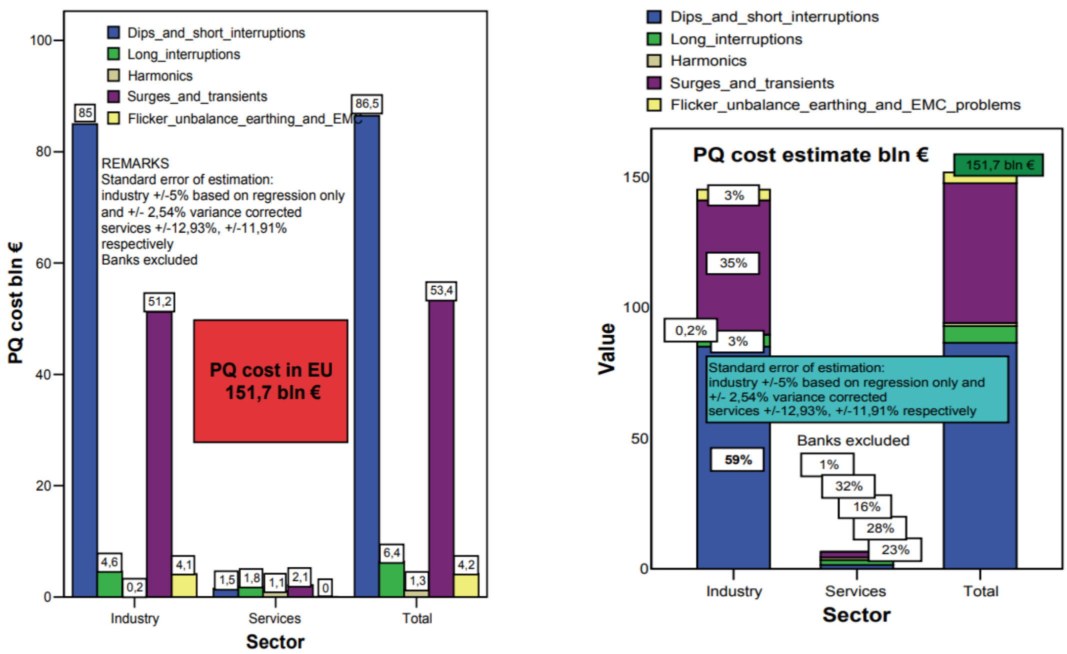

Figure 1 - Cost of power quality (PQ) wastage EU-25 by PQ Phenomenon

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[1] PAN EUROPEAN LPQI POWER QUALITY SURVEY, Roman Targosz and Jonathan Manson, C I R E D 19th International Conference on Electricity Distribution Vienna, 21-24 May 2007.

Likewise, the paper "The Cost of Power Disturbances to Industrial & Digital Economy Companies"[2] uses data that is over 20 years old, and again conclusions being derived from it may not be relevant in the modern context. The document notes that 69% of all users in the digital economy, continuous manufacturing, and fabrication & essential services sectors report no costs associated with PQ problems in a typical year. However, for a handful of large and highly sensitive users, losses from PQ phenomena are significant.

NZ ECP 36:1993 standard is more applicable to consumers with harmonic emissions that may impact other consumers. When the standard was introduced, there was no justification for the harmonic levels it prescribed. The standard addresses traditional harmonics problems of the time (e.g. problems in electrical equipment and interference with fixed line telecommunications). Owing to these issues, WEL believes it is time for a modern standard to be introduced which replaces NZ ECP 36:1993.

One of the concerns with increasing amounts of inverter-based generation, and energy storage devices, on the power system is that harmonics emissions may cause problems with other inverters, leading to a less stable power system. This problem differs from traditional harmonic problems and may require a different approach. This supports WEL's view that new technologies require new standards.

The 61000 series standards referred to in the Electricity (Safety) Regulations 2010 Act relate to low voltage connections:

- IEC 61000–3–2: Limits - Limits for harmonic current emissions (equipment input current ≤16 A per phase).
- IEC/TS 61000–3–4: Limits - Limitation of emission of harmonic currents in low-voltage power supply systems for equipment with rated current greater than 16 A.
- IEC 61000–3–12: Limits - Limits for harmonic currents produced by equipment connected to public low-voltage systems with input current >16 A and ≤ 75 A per phase.

It is understood that medium voltage connections for larger DG and DER are covered by NZ ECP 36:1993, not the 61000 standards. As these types of DG and DER connections become more common, WEL believes it is imperative to have modern standards to address the harmonics issues of modern technologies.

We have provided more fulsome answers to the questions posed in the consultation paper in Appendix B.

Should you require clarification on any part of this submission, please do not hesitate to contact us.

Ngā mihi nui

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[2] The Cost of Power Disturbances to Industrial & Digital Economy Companies, Submitted to: EPRI's Consortium for Electric Infrastructure for a Digital Society (CEIDS) By Primen, June 29, 2001.

Appendix A - Paper 2: Response to Consultation Questions

Questions	WEL Networks Comments
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.	Yes. Distributors are responsible for voltage management on their network and the voltage received by their customers. Distributors also have minimum power factor requirements at their GXPs so are incentivised to manage reactive power and place voltage and reactive power requirements on their customers.
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.	Neither option is supported. Voltage related performance obligations for distribution connected generation and energy storage systems should be set by distributors according to the characteristics of their network(s). Voltage related obligations for distributed generation and energy sources should not fall within the Code. The proper location for voltage related obligations for distributed generation is the distributor connection and operating standards. It may be desirable that all distributors have a common approach to determining voltage related obligations, but this approach does not need to be developed by the EA and system operator.
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.	No. The voltage related asset owner performance obligations in Part 8 of the Code are based on synchronous generation technologies and for the transmission system that existed many decades ago. It is not obvious that the voltage related AOPOs are optimal today or that the voltage related AOPOs for the transmission system should be extrapolated to distributed generation in distribution systems. Any threshold should be based on the ability of the distributed generation to affect voltages across the distribution network. The DG hosting capability (i.e. how much distributed generation can be injected at different parts of the distribution network) could provide an alternative mechanism. Voltage related performance obligations for distribution connected generation and energy storage systems should be set by distributors according to the needs of their network(s).

	Voltage related obligations for distributed generation and energy sources should not fall within the Code. Capacity thresholds should be determined by distributors taking into account the characteristics of the relevant distribution network. A one size fits all approach is inappropriate.
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?	It is not apparent that the existing +50%/-33% reactive power range requirement is optimal or even appropriate for the future. It is not obvious what reactive power range is appropriate for distribution networks. No analysis of the costs and benefits for any combination of reactive range has been presented so an opinion on pros and cons of any arrangement does not have much value.
Q5. Do you agree the Authority should be short listing the first voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.	No. The management of distribution voltages is outside the ambit of the Code. This should be managed by the distributors within their Connection and Operating Standards. Having voltage related obligations within the Code and Connection and Operating Standards will likely result in barriers to entry for DG and DER as distributors will be more conservative in the size of DG and DER that can be connected, and the costs of DG and DER will be increased.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	The option will complicate dispatch arrangements with two parties with potentially mutually exclusive objectives trying to control the same resource. Liability for damage to consumer appliances or outages resulting from system operator issued reactive power dispatch instructions to distributed generation is unresolved. This liability needs to be addressed prior to proceeding with this option. Duplicated voltage related obligations and monitoring and compliance systems from the Code and distributor's connection and operating standards.
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?	Inefficient overbuild of assets. Increased transaction costs for asset owners and system operator (ACS, monitoring, dispensations etc). Cost of system operator connection studies making smaller distributed generation uneconomic.

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?	The usual costs associated with complying with the Code in respect of voltage related obligations. Difficulty in simultaneously supporting voltage and meeting minimum power factor requirements when charging.
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.	Yes.
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	Avoids direct System Operator interference with distribution voltage management which reduces risks to assets and public safety. Allows voltage management to be focussed on the GXP. Helps distributors' ability to efficiently manage their networks.
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?	This question does not appear particularly relevant. An energy storage system with a point of connection to the grid is by definition not connected to a distribution network so will not directly affect a distributor's ability to manage reactive power flows across the GXP. The usual costs associated with complying with the Code in respect of voltage related obligations. Difficulty in simultaneously supporting voltage and meeting minimum power factor requirements when charging.
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.	Yes. Distributors are primarily concerned with the effects of faults on their distribution networks and to a lesser extent faults occurring on the transmission network. Accordingly, distributors may place obligations on DG to remain connected or even disconnect during certain distribution faults (e.g. to avoid islanding). Distributors will be less concerned about DG riding through transmission faults unless the lack of ride through capability of DG affects the reliability of the distribution network.
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	Yes. The fault ride through requirements should be based on faults that occur frequently enough to qualify as contingent events.

network protection considerations? Please give reasons for your answer.	Distribution network protection considerations should take precedence over Code fault ride through requirements.
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.	No. The benefits of DG connected at the GXP nominal voltage riding through transmission faults accrues mainly to the distribution network so any fault ride through requirement based on connection voltage should be up to the distributor to specify. Any threshold should be based on a thorough cost-benefit analysis. Increasing the threshold limit above 30 MW could prove more optimal.
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.	Yes.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	Costs of making existing DG compliant or seeking dispensations. Cost of monitoring performance. Reduced risk of system collapse.
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?	Costs of making existing DG compliant or seeking dispensations. Cost of monitoring performance.
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?	It is disappointing that market-based options are not being considered following the assessment. Given the long lead time for these options, should not work on the options commence as soon as possible? Market based options would provide potential new revenue streams for DG and DER rather than AOPO options which impose additional costs on DG and DER.

Appendix B - Paper 3: Response to Consultation Questions

Question	WEL Networks Comments
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.
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.
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. The existing framework needs to be updated for clarity and to accommodate technology changes. The problem of harmonic issues with inverter-based resource needs to be clarified as the issues and mitigations are likely materially different from those of more traditional harmonic issues.
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?	There should be a stronger clarification of costs and benefits. Should standards be selected to meet the requirements of the most sensitive parties affected by harmonics or be based on the requirements a more typical connected party?
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.	Owners of inverter-based resources need certainty around the likely costs associated with harmonic mitigation that they will be required to pay. There needs to be a process to manage changes in the harmonic characteristics of the network. There is a need for flexibility around and pathways for managing non-compliant plant. There is a need for proportionality in the effort and costs for required harmonic impact assessments.
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.	Yes. It is desirable that a similar harmonics allocation approach is applied in each distribution network so that developers will have lower costs in managing harmonics issues.

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?	NZ ECP 36:1993 is obsolete and needs to be updated or abandoned. The standard pushes a deterministic approach to compliance (e.g. installations are compliant or not). It is understood that the 61000 series of standards do not apply to MV connected DER so are of limited value.
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?	No.