12 November 2024

Consultation: Part 8 Code amendment proposal and addressing common quality information requirements
Electricity Authority
Via email: fsr@ea.govt.nz

Tēnā koe,

Updating common quality requirements while avoiding adverse consequences

Powerco is one of Aotearoa's largest gas and electricity distributors and is committed to our role in Aotearoa achieving a net zero economy in 2050. We supply around 357,000 (electricity) and 114,000 (gas) urban and rural homes and businesses in the North Island. We are playing our part in Aotearoa's electrification and we share the Electricity Authority's objective that the Code's common quality requirements must enable evolving technologies, especially inverter-based resources, which are crucial enablers of consumer choice and electrification.

Addressing the common quality requirements in a way that promotes the reliability of electricity supply for consumers and avoids unintended consequences in operation of the electricity system is essential. Our primary interest is the Part 8 proposals for FSR-003 and our response on this part of the consultation paper is set out in the attached table, along with brief comments on other parts of the common quality consultation. In addition, we support the ENA submissions on the 2 consultation papers. Our summary views are:

Under frequency event vs good industry practice	• The principle that a causer of an under frequency event (UFE) should be held responsible is sound in theory, however, there is risk that an EDB is deemed to have caused a UFE when operating the network according to good industry practice. • Care in drafting is needed to ensure the Code changes meet the intent. In particular, the drafting must ensure no consequential effect of tightening security requirements and reducing connection of renewables to the network.
Enabling dynamic DER analysis	• We support the Authority enhancing the form, depth and sharing of common quality information for distributed energy resources while balancing risks and costs.

This submission does not contain any confidential material and may be published in full. If you have any questions regarding this submission, please contact Gabriel Lim (Gabriel.Lim@powerco.co.nz).

Nāku noa, nā,

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POWERCO

Attachment 1: Response to consultation papers – common quality requirements

Topic	Powerco response
Part 8 Code amendment proposal FSR-003: Include distributors and energy storage systems as potential causers of under-frequency events (UFE)	
General comments on FSR-003	We support the intent of FSR-003 to hold all causers of UFE responsible, including owners of embedded generation and Battery Energy Storage Systems (BESS). However, the consultation paper is not clear about likely scenarios that would cause this occurrence. In our view, the issue may be more accurately defined as the System Operator (SO) having visibility of the potential rapid increases in demand that BESS might cause. This issue would be better managed through GXP demand forecasting and market dispatch mechanisms around non-conforming loads like BESS, rather than changing UFE obligations.
Q3.1 Do you support the Authority's proposal to amend the definition of 'causer' in clause 1.1 of the Code so that it refers to the action that results in a UFE, including an increase in electricity demand (load), and the consequential amendments to clauses 8.60 to 8.66, including proposed new clause 8.64A?	We support the principle for distributors to have the same potential liability for a UFE for actions in regard to GXP demand. But the Code proposals do not appear to respond directly to the identified issue, and are expected to create legal complexities and unintended consequences which we comment on in the following responses. The existing Code provisions for grid scale BESS and embedded DG over the 30MW limit, already cater for the actions of a BESS asset owner in their capacity as a generator, and therefore cover their potential to cause a UFE by sudden loss of dispatched infeed. This Code proposal is therefore assumed to address additional cases either where a large BESS asset owner is acting as a load or the situation where there is a sudden loss of multiple smaller generators under 30MW each, which cause a UFE. Large and rapid step increases in BESS charge/demand are likely to occur at times of lower price (eg times of high solar generation) and therefore more likely a planned action responding to price, and manageable via the market mechanisms and real time pricing, to restore the balance of supply and demand. The terminology proposed needs further consideration to clarify a participant's unplanned demand increase causing a UFE, which is distinct from a demand change due to a market response, or network management response. If market dispatch does not yet have sufficient visibility or ability to influence changes in BESS demand, then a response should target that issue, rather than focus on UFE provisions. We comment further on network management in Q3.2 below. For generators, we mandate through our utility scale distributed generation connection standard, for new generators above 1MW connecting to our Powerco network to have frequency support obligations. The rationale for enforcing this is to minimise the risk of multiple generators under 30MW tripping off due to UFE.

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Q3.2. Do you see any unintended consequences in making such an amendment?	We are concerned about potential for unintended consequences as the consultation paper does not provide a clear rationale to include distributors as potential causers of a UFE or evidence that EDBs are (or could be) causing UFE in situations where they have control. If a large DG is connected on N security and an outage or network need trips them off, this could result in an unexpected loss of infeed to the grid and a UFE since the DG masks the load. The scale of the DG would need to be relatively large (for example a single DG or aggregated group of smaller DGs ~60MW) to cause this. Network scenarios that may cause an injecting BESS or DG to be disconnected could include a sustained network fault resulting in a disconnection of a BESS or DG, or an embedded BESS or DG tripping during a network fault. A distribution network, in contrast to the grid, has a radial architecture (not interconnected), with low security and circuit redundancy, plus much lower system strength (higher impedance). This does not equate to inappropriate performance or actions on the part of either the BESS/DG owner or the distributor. We are not acting to "increase demand", which is the express intent of the Code change, but rather acting as a network operator with good industry practice, and the effect of our actions is disconnection of generation, for example through anti-islanding protection implemented on DGs, they must disconnect within 2 seconds when a loss of voltage is detected. We are concerned the proposed Code changes may interfere with this industry practice. Further, these UFE proposals could cause EDBs to mitigate the risks of being unreasonably found to be a causer of UFE, by limiting DER connection, or placing more onerous requirements on DER connections, or procuring fast instantaneous reserves from other DGs/BESS to mitigate the UFE, thus creating higher costs and unnecessary barriers to renewables and flexibility uptake. This is a significant unintended consequence when there is no clear evidence of scenarios where an EDB could cause a UFE not managed through existing protocols.
Q3.3. Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.	We are concerned that the proposals, and the two alternative options provided in the regulatory statement, do not adequately: (i) address a defined issue (ii) recognise how networks are managed under existing Code requirements or (iii) acknowledge the potential for unintended consequences. The UFE provisions target large (>60MW) load. We propose that the EA use BESS > 60MW a non-conforming load. A 60MW load is often a major portion of a GXP total demand and is unlikely to conform to any predictable patterns. If it was required to submit demand bids, and held accountable to conform with those, the risk associated with a sudden increase in demand, in a manner the market energy balance had not already accommodated, should be minimal. We also note that an expected future scenario with a large number of smaller BESS responding to market price could result in sudden increase in demand. There seems to be no plausible single event, other than price, that could cause a coincident step increase in multiple distributed BESS. As per our comment on Q3.2, this again points to a preferred alternative

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	of future proofing the market and demand forecasting mechanisms rather than UFE provisions. We also note that the UFE proposals do not recognise the potential role of aggregators in future scenarios of multiple distributed BESS. As BESS and DG aim to be close to demand and enhance flexibility, this reduces the risk of embedded DER affecting system frequency. Isolating parts of the network with DER would likely also isolate a similar amount of load, resulting in a smaller impact compared to grid-connected DER, if the DERs are mandated to stay connected and support frequency as best as they can during the UFE. We encourage the Authority to use an option which focuses on a networks' ability to manage the potential constraints under low-price scenarios, and better net demand information for the SO in scenarios where flex of demand could be widespread. As DER and flexibility become more prevalent, networks will need to manage demand more in real time. Network visibility and dynamic management will be critical alongside capability to inform the SO in real time or ahead of time of anticipated net demand. The System Operator has significant powers and capabilities to help it avoid UFEs occurring, such as procuring enough spinning reserves to manage this risk. Providing networks with similar mechanisms to manage technical performance of third parties would be a streamlined approach to manage risk of UFEs.
Q3.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	The cost benefit evaluation is very light on detail or quantification of costs/benefits of the proposals, or the alternatives identified in the document. We have also identified in our comments above that this proposed regulation may not be the most efficient response for the stated problem. We endorse the principle for a cost-benefit analysis to be proportionate to the nature of the changes proposed. However in this case we do not consider that the regulatory statement provides adequate evaluation. For example, the regulatory statement does not adequately recognise the scenarios outlined above, good network management practice, or existing Code provisions addressing the identified issue.
Other Part 8 Code amendment proposals	
Asset capability statements (FSR-002)	We support setting this requirement at individual assets >1MW. The SO should also provide the Distributor access to the ACS platform for all embedded generators connected to their network.
Speed governor (FSR-004)	We support the Authority's proposal to amend the Code to include inverter-based generation technologies, as these systems lack speed governors, unlike synchronous machines.
Excitation system (FSR-005)	We support the Authority's proposal to amend the Code to replace excitation system with voltage control system.

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Dynamic reactive power compensation devices (FSR-006)	We support the Authority's proposal to mandate that all dynamic reactive power compensation devices, such as STATCOM, undergo periodic testing. This regular testing verifies the plant's capabilities to absorb or inject reactive power within specified limits. Testing also verifies that the plant can quickly respond to sudden changes in voltage within specification.
Treating energy storage systems as only generation (not load) under Part 8 (FSR-007)	While we support clarifications of the role of energy storage systems in Part 8, and that proposals are an interim measure only while further evaluation of energy storage systems is undertaken. We query potential conflict of this proposal with FSR-003 which appears to treat an energy storage system as load for the purpose of UFE responsibility, highlighting the need to review the intent and drafting of proposals. In setting a 30MW threshold, we note two matters. First, clarification will be needed if the threshold relates to single sites/assets or aggregated assets. Secondly, if this threshold is linked to the 30MW excluded generation limit, this is expected to change in the near term.
Addressing common quality information requirements for network owners and operators (issue #6)	
The drivers, issues and roles (question 1 to 5)	SO and distributor access to modelling information must not be a replacement for meeting performance requirements. The modelling discussed in the consultation paper is primarily relevant for the SO in modelling complex dynamic interactions between multiple generators. Distributors have a more limited role in maintaining frequency in real time and even though this role is expected to increase in the future with microgrids, more BESS and DGs on the distribution network, the risks and approaches for distributors will be quite different compared to the complexity of the SO role in ensuring stability of the entire electricity system. For distributors, multiple utility scale DGs >1MW are expected to be managed through compliance with technical standards such as our utility scale DG connection standard, while multiple smaller DGs <1MW connecting into the LV network would be managed through one of our DG connection standards for <10kW or >10kW connection[1]. Voltage quality is important for distribution networks, and voltage performance can be managed locally through performance requirements to reduce any dynamic interplay between multiple devices. The ability to regulate frequency is expected to be limited at the distribution network level, but a large enough BESS has the capability to act as primary and secondary frequency response following a grid disturbance. Further, enhanced sharing of information must be designed to be compatible with, and not blur, the distinct roles of the SO, distributors and Transpower, especially for voltage management and embedded generation. The primary purpose of access to common quality information should relate to the defined role of the SO or network operator.

[1] These standards are published on our website: Utility-scale generation; Solar power for home and business

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	Currently, Powerco does not do dynamic DER analysis, however, we expect this will be needed in future, and we would benefit from an arrangement where distributors can request access to IBR and machine (synchronous and asynchronous) dynamic models. There would also be benefit in clarifying the form and depth of modelling information to assist in consistent quality information about DER and for efficient information sharing between parties. We acknowledge that a balance is required between information requirements, risk mitigation and costs.
The options (question 6 to 11)	We support either Option 2 or Option 3 in the consultation paper to improve our access to common quality information. Option 3 would provide for improved access to the common quality information for both distributors and Transpower and we acknowledge that Transpower would benefit from improved information for network planning, and this is therefore a preferred option overall. Clarifying the information requirements and enabling sharing between the SO, distributors and Transpower is the most efficient option for both generators and network operators/owners. The detail of the changes to the Code, and related processes for the SO, distributors and Transpower will be important to minimise potential issues. There is a potential risk that manufacturers might be reluctant to share proprietary information. The Authority could investigate information requirements that would mitigate this risk. For example, a focus on control functions/responses (the features) rather than detail about how those functions are implemented (the software). We expect there are also international learnings or standards to guide appropriate information requirements. Costs that are likely to arise for distributors include procurement of power systems modelling software capable of dynamic electromagnetic transients (EMT) simulations and the upskilling of staff to become competent at dynamic modelling. We do not agree that a distributor’s asset ownership and network operations roles could potentially lead to perceived or actual conflicts of interest in relation to common quality-related asset information. The regulatory system is well established to mitigate any such risk.