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Tēnā koe,

Common quality and wholesale market arrangements for BESS and BESS-hybrids – issues and options

As an electricity distribution business (**EDB**) with practical experience operating distribution-connected BESS - at Whangamatā (network reliability), Greerton (a low-voltage trial), and Ngātea (outage response) – Powerco has engaged with the Authority's BESS work programme through submissions on the regulatory roadmap for BESS (July 2025), the future operation of New Zealand's power system (August 2025), and wholesale market arrangements for BESS (December 2025).

This submission focuses on the issues and options paper only, in particular, the interface between System Operator (**SO**) dispatch and distribution network management. The Authority has noted that distribution network policy is outside the scope of this consultation.[1] However, the Authority is interested in hearing about other issues to consider,[2] and in our view the coordination gap between SO dispatch and EDB network management must be considered as part of this workstream given to potential for implementation issues or unintended consequences.

We summarise our positions below.

Theme	Powerco's position
The current Code framework is the right starting point	• The Code already draws a clear line between non-market-participant injection and demand (which the SO does not dispatch) and assets subject to SO dispatch. BESS straddles both sides of that line at the same connection point - that is the fundamental challenge. • The proposed framework extends the existing embedded generation dispatch pathway to BESS charging, without resolving the coordination gap this creates at the distribution interface.

[1] Electricity Authority, Common Quality and wholesale market arrangements for BESSs and BESS-hybrid stations – consultation papers, 19 May, para 2.29(b).
[2] Electricity Authority, Common Quality and wholesale market arrangements for BESSs and BESS-hybrid stations – consultation papers, 19 May, Para 2.28.

Theme	Powerco’s position
The coordination gap is real and already causing problems	• Under clause 8.25(5), the SO can already require embedded generators greater than 10 MW to submit offers, with no obligation to coordinate with the EDB whose network they are connected to. • Lodestone's Pāmu Rā ki solar farm in Whitianga - connected to Powerco's Coromandel network - is a live example. Both the SO and Powerco can curtail the plant, and no Code rules coordinate how. Powerco and the SO have adopted an informal 'hierarchy of control' arrangement, but this is a workaround, not a solution.
The proposed BESS framework will make the coordination gap worse	• Extending dispatch obligations to the charging side of BESS - without first resolving SO/EDB coordination - gives the SO a broader reach into distribution networks than currently exists, before the Future System Operator (**FSO**) workstream has delivered the framework that ensures long-term benefit to consumers. • Each incremental expansion of SO reach without a corresponding coordination mechanism is, in practice, a default step towards the transmission-centric FSO model (option 1) - without a deliberate policy choice to go there.

Implementation issues must be addressed	• The Authority must address implementation issues in designing the Code amendment including:
	  ○ Clarify if distribution-connected BESS are within the scope of the proposed dispatch obligations
	  ○ Resolve the ”hierarchy of control” issue to ensure there are no conflicts in coordination. The Pāmu Rā ki arrangement provides a working solution.
	  ○ Commit to an FSO workstream timeline before the Code amendment takes effect and confirm interim protections until that workstream is complete.

We set out our thoughts in more detail in the following. We are always keen to discuss the ideas in our submissions. If you have any questions, please contact Emma Wilson (emma.wilson@powerco.co.nz).

Nāku noa, nā,

EWilson

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1. Current Code is a useful starting point

The consultation papers do not clearly distinguish between resources that are subject to SO dispatch and those that are not. That distinction matters for understanding what the proposals are actually doing.

Most injection and offtake on distribution networks is not dispatched by the SO. Embedded generators below the 30 MW threshold in clause 8.21(1) are excluded generating stations - they inject freely, other than when a limit is imposed by the distribution operator. Uncontrolled load simply draws from the network at spot price. Neither is directed by the SO; both are non-market participants in relation to their respective flows.

The Code provides two separate pathways for bringing assets under SO dispatch. For generation, clause 8.25(5) allows the SO to conditionally require embedded generators above 10 MW to submit offers; those embedded generators are then caught by the mandatory offer obligation in clause 13.6. Smaller embedded generators face only an information obligation under clause 13.25 and may offer at $0 under clause 13.26. For demand, dispatchable load is handled through an entirely separate pathway - a "dispatch-capable load station" (DCL) approved under clause 13.3A. These two pathways are architecturally distinct. An asset either offers injection or bids demand, at separate connection points or under separate approvals.

BESS is the first asset class that routinely occupies both sides of this architecture at the same connection point. When discharging, it looks like embedded generation and the 8.25(5)/13.6 pathway applies. When charging, it looks like demand - but it is not a DCL, and the DCL pathway was not designed for grid-scale storage. The proposed framework is, in effect, an attempt to extend the generation dispatch structure to cover the charging side. Powerco does not oppose that objective but the manner of implementation matters - particularly for assets embedded on distribution networks.

2. There is a coordination gap where the SO reaches over an EDB

The 8.25(5) pathway already gives the SO the ability to require an embedded >10 MW generator on a distribution network to submit dispatch offers - without any obligation to consult the EDB whose network that generator is connected to. The EDB cannot override the requirement, and the Code provides no mechanism for managing conflicts between SO dispatch instructions and the EDB's own network management needs.

This is not a theoretical concern. In our submission to the SO on its strategy refresh (February 2026), Powerco described a live example: Lodestone Energy's recently commissioned Pāmu Rā ki solar farm in Whitianga, connected to Powerco's distribution network on the Coromandel Peninsula and offering into the wholesale market. As we note there:

> *"Currently both the SO and Powerco have the ability to curtail the same plant and there are no rules coordinating how roles and responsibilities of doing so. We've approached this situation with the SO adopting a 'hierarchy of control' approach. Under this logic, the lowest dispatch value always wins, allowing any party to lower the threshold as needed, while preventing conflicting signals from compromising either distribution, customer or transmission system."*

The arrangement for Pāmu Rā ki works because the SO and Powerco have agreed to it bilaterally. It is not a Code right. There is nothing to bind either party in interpretation, and no framework for extending it to other assets or other EDBs. The same structural gap applies to any BESS connected to Powerco's network - compounded by the fact that a BESS switches between injection and demand modes, meaning both the generation dispatch pathway and a demand dispatch obligation could apply at different times from the same connection point.

The proposed Code amendment extends the 8.25(5)/13.6 structure to BESS charging. From a distribution perspective, this makes the problem worse as it increases the SO's operational reach into distribution networks without creating any corresponding coordination obligation. The Authority's response - that BESS owners can manage distribution constraints by pricing trades or limiting bid quantities - treats a network management problem as a commercial one. For an EDB coordinating BESS primarily for reliability purposes, that is not a workable answer.

The current proposal continues a pattern where SO roles expand incrementally but EDB tools to manage the resulting interface do not. The cumulative effect is a default drift towards a transmission-centric operating model - not by deliberate policy choice, but by regulatory accumulation. The Authority has indicated a preference for the hybrid FSO model (option 2). Decisions that entrench SO reach without resolving the coordination question will work against a hybrid model.

3. The Authority can address these issues now

In response to para 2.28 (other issues the Authority should take into account) and consultation question 4.4 (implementation issues and unintended consequences), the Authority can:

- **Clarify the scope for distribution-connected BESS.** The Code amendment should state explicitly whether BESS assets connected to distribution networks - below the grid connection point - are within scope of the proposed dispatch obligations, and how the 10 MW threshold applies to them.
- **Resolve the "hierarchy of control" issue.** The Authority could build on the arrangement Powerco and the SO have informally adopted for Pāmu Rā ki - lowest dispatch value wins; neither party can override the other's network management constraint – to ensure there are no conflicts in coordination which might adversely affect the long term interests of consumers.
- **Commit to an FSO workstream timeline before the Code amendment takes effect.** The proposed Code amendment is scheduled to come into force in September 2026. The FSO workstream - the vehicle the Authority has identified for resolving SO/DSO coordination - has not committed to a timeline. The Authority should publish that timeline before September 2026, and confirm what interim protections will apply to distribution-connected BESS owners until a permanent coordination framework is in place.

4. Responses to consultation questions

Section 3 — Terminology: Q3.1–Q3.3

Powerco supports the proposed 5-level generating asset classification structure. To support implementation, the structure should remain neutral on the question of which assets are subject to SO dispatch. For distribution-connected BESS, some assets will fall below the 10 MW threshold for mandatory offer obligations and will be operated by EDBs primarily for network management rather than market participation. The classification structure should not inadvertently bring such assets within SO dispatch obligations designed for utility-scale market participants.

Section 4 — Asset Owner Performance Obligations (AOPO) for idle BESS: Q4.1–Q4.5

Q4.1 — Definition of "idle". The definition of "idle" as a BESS connected to the network but not actively charging or discharging is workable for market purposes. From an EDB perspective however, a BESS that appears idle in market terms may be actively fulfilling a contractual obligation to the EDB, held in reserve for a network constraint relief event. We suggest the definition confirm that "idle" for AOPO purposes has no bearing on the validity of EDB contractual arrangements that restrict a BESS from operating during certain periods.

Q4.2 and Q4.3 — Frequency and voltage obligations for idle BESS. We have no objection in principle to frequency management and voltage support obligations applying to idle BESS. However, if an idle BESS is also subject to an EDB contractual arrangement, the interaction between SO AOPO requirements and EDB operational authority should be clarified, this is the coordination issue described in section 2 above.

Q4.4 — Implementation issues and unintended consequences. As set out in section 2, the primary implementation risk is the absence of any Code mechanism to resolve conflicts between SO dispatch instructions and EDB network management requirements at the same connection point. The proposed extension of dispatch obligations to the charging side of BESS deepens this gap without addressing it. The Pāmu Rā ki arrangement is a live illustration of the problem and of the inadequacy of bilateral workarounds as a solution.

Q4.5 — Benefits and costs. The primary cost of extending BESS dispatch obligations without first resolving SO/EDB coordination is the risk of irreconcilable instructions, the SO dispatching a BESS in a manner that conflicts with the EDB's contracted use of the same asset, with no Code mechanism to determine which instruction prevails. This creates operational and commercial uncertainty for BESS owners and weakens the investment case for EDB-contracted distribution flexibility.