25 August 2025

Submissions
Electricity Authority
Level 7, AON Centre
1 Willis Street
Wellington 6011

Via email: taskforce@ea.govt.nz

ERGANZ SUBMISSION ON ESTABLISHING AN EMERGENCY RESERVE SCHEME

The Electricity Retailers' and Generators' Association of New Zealand ('ERGANZ') welcomes the opportunity to provide feedback on the Electricity Authority's consultation paper, 'Establishing an Emergency Reserve Scheme' from late July 2025.

ERGANZ is the industry association representing companies that sell electricity to Kiwi households and businesses. Collectively, our members supply almost 90 per cent of New Zealand's electricity. We work for a competitive, fair, and sustainable electricity market that benefits consumers.

Executive Summary

ERGANZ supports an Emergency Reserve Scheme ('ERS') as a penultimate resort tool to reduce the likelihood and extent of involuntary disconnection when acute, short duration supply shortfalls occur. An ERS must sit late in the operational hierarchy, be used infrequently, and preserve wholesale market signals. The Authority's framing of ERS as penultimate resort, with activation after market options and before involuntary load shedding, is appropriate.

Price signals must remain paramount and scarcity pricing must continue to do its job. We therefore strongly support "add back" of ERS activations into nodal load schedules so prices reflect true scarcity and continue to guide both short run operation and long run investment.

Retailers already have bespoke demand response agreements with large customers and so protecting existing commercial demand response is important. The ERS must require robust additionality so it does not crowd out or double pay for these arrangements, nor dampen incentives for parties to contract in the market.

Recent tight conditions have been driven primarily by the rapid decline in domestic gas reserves, especially at Maui and Pōhokura. That context matters when weighing any new backstop. Gentailers are adding new generation supply quickly. New Zealand is currently in a "renewables boom", 2024 was the biggest commissioning year since 2007, with 4 percent of total capacity added. The project pipeline includes more than 45 GW, with 16 GW planned before 2030.

ERGANZ supports competitive tendering against a cap at VoLL, as an interim, using $35,305/MWh as proposed, with costs primarily recovered from loads, nationalised rather than islanded, and pre qualification so procurement can occur close to real time.

It makes more sense to implement with a staged approach and light touch. Start with large, single site industrial demand response (DR) while setting clear M&V for aggregations, and avoid complex market system changes. The Authority's phased, minimum viable product concept is sensible.

Why this matters

The Authority's consultation paper makes clear that an Emergency Reserve Scheme ('ERS') would operate as a penultimate step in the hierarchy of system security tools, sitting after market-based and controllable load responses have been exhausted but before involuntary load shedding is imposed. We agree with this framing and consider that codifying the sequencing is critical to reduce moral hazard and ensure that parties remain responsible for managing their own risks wherever possible.

Maintaining market integrity is also essential. The Authority has proposed that any demand response activated under the ERS be "added back" when calculating nodal prices so that scarcity pricing signals remain intact. This is important, both to preserve short-term operational incentives and to maintain the long-term investment signals on which the electricity market relies.

We also support the Authority's proposals on additionality. Excluding demand response that is already offered into dispatchable demand, dispatch notification, or instantaneous reserves, as well as load contracted under retailer or distribution company arrangements, will help preserve the effectiveness of existing commercial mechanisms that are functioning well today. Similarly, excluding controllable load expected to run in grid emergencies ensures the ERS delivers incremental system value.

On the question of process, the proposed five-phase procurement and activation model, aligned with the System Operator's existing practices and communications such as CAN and GEN notices, appears sensible and pragmatic. Using established tools like the New Zealand Generation Balance (NZGB) for procurement and Non-Response Schedule residuals for activation ensures consistency with current system security management.

Finally, we agree that the costs of the ERS must be capped at the value of lost load (VoLL). The Authority's proposal to use a transitional VoLL of $35,305/MWh, indexed for inflation from the figure embedded in the Code, is an appropriate interim step pending the fuller review of VoLL settings. This approach ensures the scheme can be implemented quickly while maintaining economic discipline on costs.

Retailer and gentailer priorities to consider in ERS implementation

Retailers and gentailers already have in place a range of practical arrangements that the ERS must respect. Over recent years, retailers have developed many bespoke curtailment and load-shifting contracts with their large customers, which are designed to manage peak risks and exposure to scarcity events. These agreements are effective and should not be undermined by the ERS. To avoid the scheme "buying away" demand response that is already contracted, it is essential that strong additionality tests are applied and that a clear registration process is established for pre-existing arrangements.

The wholesale market itself must remain the primary coordination mechanism for responding to scarcity. Gentailer submissions on scarcity pricing have consistently emphasised the importance of preserving price signals and calibrating any changes with great care. Scarcity prices are what incentivise the right operational behaviour in the short term and the necessary investment decisions in the long term.

It is also important to acknowledge the underlying supply story. The tight periods that have recently stressed the system have coincided with a significant decline in gas production, particularly from the Maui and Pōhokura fields. MBIE has reported that gas output in 2024 fell materially as a result of this natural decline. The most effective long-term solution to this challenge is not to rely permanently on emergency schemes, but to continue developing flexible new capacity.

This development is already occurring at pace. We are currently in a "renewables boom" with New Zealand's installed generation capacity increasing 10% in just the last five years, an increase of 909 MW. In fact, 2024 was the biggest commissioning year since 2007. The current project pipeline includes more than 45 GW, with 16 GW planned before 2030.

Taken together, these realities strengthen the case for ensuring that the ERS is targeted, temporary, and sparingly used. It should be designed as a last-resort safeguard to complement, not substitute for, the market signals and investment that are already working to deliver a more secure and renewable electricity system.

Key design elements

In terms of eligibility, ERGANZ supports the inclusion of both large industrial consumers and aggregations of smaller consumers, provided they can demonstrate robust measurement and verification. By contrast, we agree with the Authority that market-facing generation and grid-scale batteries should not be eligible, as these assets should continue to operate through the wholesale market. There may be a case, however, for a very narrow pathway for behind-the-meter generation or batteries to participate, so long as they are genuinely additional, not already contracted for network support or site resilience, and subject to strict additionality requirements and coordination with distribution businesses.

On procurement timing, we support the use of competitive tendering alongside a pre-qualified panel of providers. Procurement should take place as close as practicable to the period of risk, ideally within four weeks, but with flexibility for the System Operator to run shorter-notice tenders as forecast certainty improves, and to target procurement by location when appropriate.

We also support the use of established forecasting and trigger tools. The New Zealand Generation Balance (NZGB) should serve as the procurement trigger, set at the point where N-1 falls below zero, while the Non-Response Schedule residuals should be used to determine activation, with pre-activation signalled when the NRS is negative. It will be important that the System Operator incorporates forecast uncertainty, such as wind forecast error, into these calculations to improve accuracy.

Activation itself should occur after gate closure so that all available market resources are dispatched first. We strongly support the use of “add-back” to maintain scarcity pricing signals, which will be crucial in preserving both operational discipline and long-term investment incentives.

On pricing and settlement, we favour flexibility, allowing providers to offer availability, pre-activation, and activation pricing structures, provided these remain within the cap set by the value of lost load (VoLL). Settlement should leverage existing ancillary-services processes to ensure simplicity and efficiency.

In terms of cost allocation, we agree that costs should be recovered nationally from loads. As a refinement, the Authority could consider using part of the loss and constraint rentals as an offset to smooth consumer bill impacts while still maintaining appropriate market incentives.

Performance requirements must be clear. Providers should be subject to due diligence and testing, required to confirm their availability at the pre-activation stage, and should forfeit availability or activation payments if they fail to deliver. We do not see the need for additional punitive penalties, which may only serve to deter participation.

Finally, coordination with distribution businesses will be essential. Distributors should be notified in advance of the sites participating in the scheme, as well as of any planned curtailment or restoration, to ensure there is no double counting of load reductions and to avoid network issues during ramp-down or ramp-up periods.

Consultation questions

Questions	Comments
Q1. Do you agree with our rationale for establishing an ERS? Why/why not?	Support in principle. Used as a penultimate resort (after market and controllable load tools and before involuntary disconnection), an ERS can reduce uneconomic load shedding and improve consumer outcomes in rare events, provided scarcity price signals are preserved and additionality is enforced.
Q2. Are there other factors or risks you consider relevant to our decision to implement an ERS?	Crowding out of existing retailer–customer DR contracts unless additionality is explicit and enforced.

	Moral hazard if ERS is perceived as insurance; mitigate via late stage activation, add back, and infrequent use. Baseline gaming risk for aggregations; mitigate via stringent M&V, telemetry, and audits. EDB operational impacts from rapid load swings; require coordination protocols with distributors.
Q3. Do you agree with our proposal that only demand-side flexibility, including by industrials and aggregations of smaller consumers, should be eligible to provide ERS?	Yes. This best protects market integrity. Include aggregations where they meet common M&V/telemetry standards.
Q4. Are you aware of any off-market generation or batteries that may not be activated in an emergency if they are not included in an ERS? Please provide details of the type and scale of these resources.	Members report limited pockets of behind the meter generation primarily installed for site resilience or network support. We do not seek broad eligibility, but suggest the Authority consider a narrow, strictly additional pathway (opt in, with proof of non use in emergencies absent ERS and EDB sign off).
Q5. Do you agree with our proposed design elements for procurement of ERS by the System Operator, including the procurement process, timing and trigger?	Agree. Competitive tender, quantities set by identified shortfall, and trigger linked to NZGB N 1<0 are appropriate. Allow shorter notice tenders where forecast accuracy increases.
Q6. Do you consider that procurement up to 4 weeks in advance of an identified need, coupled with a pre-approved panel of providers, will be effective and provide adequate time for potential providers and the System Operator?	Yes, if the SO can flex timing (e.g., 1–2 weeks) when confidence tightens, and if panel onboarding (due diligence, technical standards) is continuous.
Q7. Do you agree with our proposed pre-activation and activation processes for use of ERS?	Agree. Pre activation 1–36 hours ahead and activation up to ~1 hour ahead (ideally after gate closure) balance provider preparedness with market primacy.

Q8. Do you agree that the System Operator should be required to update relevant planning processes to take account of forecast uncertainty? If so, how do you consider this should be done?	Yes. Incorporate wind forecast error and other uncertainty explicitly in NZGB and NRSS/NRS, calibrating with back testing against recent low residual events.
Q9. Do you agree with our proposed compensation and price settings for the ERS, including proposed measures to ensure overall unit costs do not exceed VoLL?	Support. Flexibility for providers to reflect real costs; competitive tendering; reasonable endeavours to procure below VoLL; and standard ancillary services settlement.
Q10. Do you consider that the System Operator should also be required to ensure overall costs during an ERS activation are less than VoLL? If so, how do you consider this could be practically achieved in the available time?	Preferable where practicable, but not if it slows time critical activation. Our preference is the proposed ex ante procurement check against VoLL plus ex post transparency/assurance on value delivered.
Q11. Do you agree with our proposal to 'add back' activated ERS into nodal load schedules to maintain scarcity pricing?	Strongly support. This is pivotal to avoid depressing prices below scarcity levels and to maintain investment signals.
Q12. Do you agree with our proposed settings for cost allocation and settlement of ERS costs? Do you consider an alternative cost recovery approach would be preferable and if so why?	Broadly support allocation to loads, nationally, with pre event costs spread across relevant months and event costs allocated to loads consuming during the event. We invite further analysis of a partial LCE offset to smooth consumer bill impacts without distorting incentives.
Q13. Do you agree with our proposed settings to manage non-performance by ERS providers?	Support due diligence, testing, pre activation confirmation and forfeiture of availability/activation payments on failure. We do not support punitive penalties that would deter entry.
Q14. Do you agree with our proposed information and publication settings to enable the effective operation and monitoring of the ERS? Is there additional information you consider should be made available to potential providers, the Authority, other industry participants or the public?	Support the proposed EUE assessments, NZGB publication, quarterly ERS procurement and activation reports (quantities, unit costs), and provision of selection rationales to the Authority. Add: publish event level post incident reports (with appropriate confidentiality protections) within 20 business days.

Q15. Are there other scheme design elements that the Authority should consider?	A registry of pre existing retailer/EDB DR contracts (summary form) to operationalise additionality and avoid double counting. Baselines: adopt robust, tamper resistant baseline methods (e.g., weather normalised, business day controls). Distribution protocols: minimum notice, ramp rate guidance, and restoration coordination with EDBs.
Q16. Do you agree with our high-level evaluation of the proposed ERS against our guiding principles?	Agree your assessment: the proposed design maximises competition, supports secure supply, minimises long run costs, and fits strategically with flexibility workstreams—provided add back and additionality remain non negotiable.
Q17. Is there any additional information the Authority should consider in evaluating a proposed ERS design?	Undertake a cost-benefit analysis that includes dynamic efficiency (investment responses to preserved scarcity prices) and counterfactual crowd out of retailer DR.
Q18. Do you think there are any elements of the proposed scheme design which require more time for implementation and should be delayed beyond Winter 2026? If so, please identify the relevant elements and indicate when you consider they could be implemented.	Residential/small site aggregations: phase in once common M&V/telemetry standards are settled. Forecast uncertainty updates: implement minimum viable upgrades for Winter 2026; iterate thereafter.
Q19. Do you agree with the Authority's proposal to set VoLL at $35,305 per MWh for the purposes of the ERS, and proposal to review VoLL and security standards more broadly?	Support using $35,305/MWh for ERS on a transitional basis and prioritising a Code level VoLL and security standards review.
Q20. Are you likely to be interested in participating in an ERS, such as the scheme outlined in this paper?	N/A
Q21. Are there any other implementation considerations or related issues the Authority should consider in relation to an ERS?	Settlement mechanics for aggregations (portfolio level data, verification, audits). Consistency with OCCs: clarify interactions and payment logic where OCCs and ERS overlap.

	Sunset/review clause: formal review after Winter 2026 with the option to scale back if market conditions improve (e.g., as new capacity arrives).
Q22. Are there other matters that the Authority should consider in relation to an ERS?	Communications playbook aligned with CAN/GEN and EDB protocols. Learning by doing: start with an MVP scope (industrials), publish lessons learned, then extend participation and refine baselines.

Conclusion

ERANZ would like to thank the Authority for considering our submission.

If there are any outstanding questions or a need for further comments, please let me know.

Yours sincerely,

Kenny Clark
Policy Consultant