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Electricity Markets Policy
Building, Resources and Markets
Ministry of Business, Innovation and Employment
PO Box 1473
Wellington 6140

Via email: electricitymarkets@mbie.govt.nz

ERGANZ SUBMISSION ON A PROPOSED RELIABILITY OBLIGATION TO MANAGE DRY-YEAR RISK (ENERGY PACKAGE, ACTION 2.5)

The Electricity Retailers' and Generators' Association of New Zealand (ERGANZ) welcomes the opportunity to comment on the Ministry's consultation paper, 'A proposed reliability obligation to manage dry-year risk' from June 2026.

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

Executive summary

ERGANZ is comfortable with some assessment of whether there is adequate security to manage dry-year risk, and we want to work constructively with the Government on the mechanisms best able to give assurance that this security will be met.

ERGANZ welcomes MBIE's decision to frame the response around the market rather than central procurement, a capacity market, or a strategic reserve, and we agree with the reasons the paper gives for setting those wider options aside. However, in our view, MBIE's response must operate through market price formation rather than displacing it. As our analysis cautions, an obligation that overlays administrative judgements of need and acceptable response onto nodal prices and contracts risks reproducing the very features of the mechanisms MBIE has set aside.

Our submission is offered in a constructive spirit. ERGANZ's members share the Government's goal for an electricity system that is renewable, affordable, and keeps the lights on. Our purpose is to help officials arrive at a workable, proportionate design that delivers reliability at the lowest sustainable cost to consumers.

New Zealand’s electricity system has changed materially since winter 2024. Encouragingly, New Zealand's dry-year risk is receding as the renewables build accelerates and demand flexibility matures. Concept's modelling finds that the mean-hydrology need for thermal generation had already fallen by around 40 percent between early 2024 and early 2026, and is likely to fall by more than 70 percent by 2028.

The ASX forward curve corroborates this: prices for 2027 to 2029 have settled back towards the long-run marginal cost of new generation, indicating a market finding a new equilibrium with less gas and more renewable supply rather than one pricing in a sustained dry-year premium.

As Concept Consulting’s analysis shows, and as the ASX forward price curve now confirms, 2024 is better understood as a gas-deliverability event during a hinge year in the transition, rather than as evidence of a failure in market design.

Before imposing substantial new obligations on market participants, officials should assess how the risk profile has evolved and what the Energy Package measures already underway will deliver. On this basis, ERGANZ does not support the long-term or short-term obligations as currently conceived. In our assessment, both obligations carry too high a risk of material harm to consumers to proceed in their present form.

ERGANZ remains ready to work with officials on any assessment of adequacy, and on alternative ways to give the assurance the paper seeks. Our detailed position is as follows:

- ERGANZ does not support the long-term obligation as currently conceived. It carries too high a risk of material harm to consumers, for the reasons set out in Part 2. At a minimum, the trigger, allocation and compliance settings would each need to be made robust and proportionate before any forward obligation of this kind could be considered workable.
- ERGANZ does not support the short-term obligation either. As drafted, it risks interfering with the very price signal it claims to preserve, may duplicate cover the sector is already securing through the Huntly Strategic Energy Reserve and, prospectively, an LNG import facility, and duplicates the scarcity-pricing and customer-compensation provisions already in the Code. It should not proceed in its current form.

A detailed technical analysis prepared independently by Concept Consulting Group accompanies this submission at **Appendix A**. We commend its analysis to officials as the evidence base for the concerns set out in this submission.

Long-term obligation

ERGANZ does not support the long-term obligation as drafted, because it carries too high a risk of material harm to consumers, for the reasons detailed below. We can nonetheless see value in a forward-looking assessment of adequacy, and we would engage constructively on one. We support building on existing regulatory architecture rather than constructing a new regime from first principles (Q4), and we can see merit in a forward response where a genuine forecast shortfall is identified (Q5), though not in the penalty-backed form proposed. The following design issues would each need to be resolved before any obligation of this kind could be workable or command industry confidence.

Does the obligation actually produce new build?

The obligation compels regulated parties to *secure cover*, not to build new generation. Because the cheapest qualifying cover is usually existing plant, notably Huntly, the obligation risks reinforcing the very “investment timing” problem the paper identifies in Appendix A: participants will rationally contract with existing plant rather than underwrite new build.

MBIE’s proposition (paragraph 86) that compliance contracts will “tilt” sellers’ investment cases only holds if those contracts carry the tenor that new build requires. The paper’s own commissioned analysis concludes that bankable offtake for security-of-supply assets may need to run 15 years, and more likely 20 to 25 years. A near-term purchaser obligation assessed twelve months out does not obviously generate contracts of that length.

We have considered the argument, advanced by some, that this concern is overstated: that competition among obligated parties for a finite pool of existing cover will itself bid up the price of that cover, and that higher cover prices will in turn support new build, so that any party unable to secure existing cover will be driven to underwrite new supply. This is the mechanism by which a well-functioning market is supposed to work, and ERGANZ does not dispute that stronger price signals will, over time, incentivise new investment.

The difficulty is not the direction of the effect but its *nature and its cost*. The new build that qualifies as dry-year cover is not marginal renewable generation, which is already arriving in volume. It is firm, dispatchable, long-duration capability, which is precisely the most expensive form of new supply and the hardest to finance, for the tenor and revenue-certainty reasons the paper itself sets out.

Therefore, the chain of reasoning does not end at "higher prices, therefore more build, therefore lower prices." It ends at "higher prices, therefore more *firm* build, therefore a more reliable system at a higher standing cost."

Competition for cover does not make the underlying firming cheaper, it places a cost on consumers every year, not just in dry-years. Whether this is a good deal for consumers depends entirely on how much cover the obligation compels, which returns us to the sizing question in Part 4. The mechanism is coherent but introduces new and material costs, and the paper should not present it as though reduced tail risk flows through to lower average prices automatically.

Recommendation 1
MBIE should clarify how the long-term obligation produces new firm build rather than merely competition for existing cover, and should acknowledge explicitly that the qualifying build is firm and dispatchable capability whose higher cost is borne by consumers in every year. Consideration should be given to whether qualifying contracts must meet a minimum tenor for new-build resources if the obligation is to close the investment-timing gap it identifies.

Allocation, the free-rider gap, and the system-wide benefit

The proposed allocation requires the large generators to cover 100 percent of the identified shortfall while representing less than 100 percent of winter demand (paragraphs 76 to 77). Load outside the cohort benefits from the resulting reduction in system-wide risk without contributing to it. ERGANZ asks officials why this cross-subsidy was preferred, and whether a broader contribution mechanism was considered.

New generation built by a regulated party confers a system-wide reliability benefit because it reduces the probability of a supply deficit for everyone, whether or not it is contracted to a third party. It is fair to observe that this benefit is real and that it partly answers the concern that uncontracted new capacity does nothing useful, it plainly does, because it reduces the physical risk of shortage at source.

The allocation issue is therefore not that new capacity fails to help the system. It is one of *incentive alignment*. Under the proposed design a party is credited only with its own allocated share of cover, so a member who has already secured cover for its own load captures little additional compliance value from building capacity that benefits the whole system.

The system-wide benefit is socialised while the compliance credit is not. That weakens, at the margin, the incentive to build beyond one's own obligation, even though such build is exactly what the policy is trying to encourage.

> **Recommendation 2**
> MBIE should reconsider the allocation and crediting rules so that a participant which secures cover conferring a system-wide benefit is not disadvantaged relative to the free-rider load it protects. Options include a broader contribution base, or a crediting mechanism that recognises system-wide firming contributions rather than only own-load cover.

The SOSA as the trigger, and the tension with market signals

The mechanism rests on the SOSA and the Expected Scenario. ERGANZ holds concerns about using such a forecast of this kind as a binding, penalty-backed trigger. Forecasting winter energy adequacy several years out is inherently uncertain; the SOSA has a documented history of demand-projection error, as Concept demonstrates; and no reasonable investment of effort can make it fully accurate.

Participants could face penalties driven by forecast error rather than by any genuine failure to act. There is a further risk that the regime incentivises costly effort in contesting and refining the measure, which is probably not the best use of sector expertise.

A deeper concern is the potential for the SOSA to diverge from the market's own signal. Forward prices on the ASX have recently softened to levels suggesting the market does not currently see a need for large amounts of additional investment, while a SOSA-driven obligation could simultaneously assert that more cover is required. We recognise these two signals measure different things, with the forward curve reflecting traded positions and current risk appetite over a three-to-four year horizon, whereas the SOSA models physical adequacy under an expected scenario further out. They can therefore diverge without either being wrong.

That, however, is precisely the difficulty. The obligation elevates the administrative signal to a binding, penalty-backed requirement, overriding the market signal wherever the two diverge. MBIE has not explained why the SOSA should take precedence over the market's own assessment in this way. Nor has it explained how the resulting investment is to be funded where the market itself sees no need for it. If hedge contracts must sit above cost to support that investment, where does that margin come from, and who pays it? We do not think this tension is adequately confronted in the paper.

Relatedly, the factor that moves the SOSA most is the assumption about access to fuel. This hands considerable market power to fuel suppliers. A rational gas producer can price the expected regulatory penalty into the gas it sells, and because gas frequently sets the marginal price, that penalty is then multiplied across all dispatched generation. The obligation could thus raise wholesale prices through a channel that has nothing to do with genuine scarcity. We encourage officials to analyse this further before the obligation proceeds.

Recommendation 3
MBIE should (a) set out how the regime will treat forecast error so that participants are not penalised for SOSA inaccuracy rather than genuine non-compliance; (b) explain how it reconciles a SOSA-driven obligation with contrary signals from forward markets, including how the resulting investment is funded; and (c) assess the risk that fuel suppliers price the regulatory penalty into fuel, lifting the marginal price across all generation.

Parties that already hold firm cover

The obligation does not fit well for obligated parties whose exposure is already firm. Where a large purchaser such as the New Zealand Aluminium Smelter holds a firm supply contract, it does not need additional winter cover in any real sense; it is likely to discharge the obligation by buying an option it never intends to call.

On the remaining long-term design questions, ERGANZ supports a technology and fuel-neutral definition of qualifying cover (Q10), and a compliance standard focused on whether the obligated party has secured a clear and enforceable position, rather than a full operational audit of every underlying asset (Q11). We support a de minimis threshold in principle (Q7), while noting the concerns above about parties whose exposure is already firm.

The short-term obligation

ERGANZ does not support the short-term obligation as drafted. Our chief concern is that it risks interfering with the price signal it claims to preserve, may duplicate cover the sector is already securing, and has not been reconciled with existing Code mechanisms directed at the same situation. We recommend it not proceed in its current form (Q15).

Penalty-avoidance and defensive water management

The penalties proposed are substantial. Non-compliance risks the greater of $10 million, three times commercial gain, or 10 percent of turnover, while conservative storage management carries no equivalent penalty. As winter tightens and the system approaches the trigger, the rational response for a hydro generator is to hold storage higher than efficient water value would dictate, so as to reduce the probability that the obligation comes into force.

This defensive conservation withdraws lower-priced hydro offers, raises water values and offer prices, and lifts the marginal price, producing higher wholesale prices in near-trigger periods that are driven by penalty-avoidance rather than genuine scarcity. Because the trigger is based on national storage levels rather than price, widespread conservation can keep storage high while prices rise, which is the premium price consumers pay for this additional security of supply insurance.

It is fair to observe, as some have, that sustained higher prices of this kind would themselves signal a need for investment and, over time, incentivise new supply that reduces the underlying risk. We accept that. But this is a second-order, lagged effect that does not cure the immediate problem: in the near-trigger window the consumer faces higher prices without any corresponding scarcity to justify them.

Whether that period is genuinely “close to the worst outcome for consumers” can only be judged with hindsight, and we do not overstate it. The narrower design point is that the penalty asymmetry creates a predictable behavioural incentive to manage storage defensively, and MBIE treats this (at paragraph 153) only as a matter for compliance assessment after the fact, rather than as an incentive the penalty structure itself creates in advance.

Because the obligation formalises once storage sits at or below the notification curve for 21 days, participants have a strong incentive to manage to a specific storage level rather than to efficient water value. There is a related incentive to draw storage down at just under 18 GWh per day to avoid the trigger, or faster if positioned to be a net supplier of compliant cover, in each case because the trigger alters water values around the compliance window. These are distortions to efficient dispatch that the current market does not contain.

Recommendation 4
MBIE should recognise defensive water management as a predictable incentive created by the penalty asymmetry, not merely a compliance-assessment issue, and should account for this in future cost-benefit calculations.

Interaction with existing Code mechanisms

While the consultation paper touches on scarcity pricing and the Customer Compensation Scheme in passing (Appendix A, footnote 3), it does not reconcile the proposed short-term obligation with those existing Code mechanisms. That is a significant gap. Those mechanisms are directed at the same end state the short-term obligation addresses, namely the system moving into a genuinely stressed position, and they already sharpen incentives during acute scarcity. Officials should establish whether both are needed and, if so, ensure they complement rather than duplicate or contradict one another.

In particular, the two regimes should sit on a coherent escalation path. It would be incoherent for the short-term obligation's penalty to exceed what the customer-compensation rules already provide once a conservation campaign is triggered, because that would invert the intended escalation, penalising a generator more for an anticipatory fuel shortfall than the Code imposes when actual curtailment of consumers occurs. If pursued, the penalty under the short-term obligation should be calibrated as a lower rung on the same ladder, not a free-standing and larger exposure.

> **Recommendation 5**
> MBIE should map the short-term obligation against the existing scarcity-pricing and customer-compensation provisions in the Code, confirm that both are necessary, and if so calibrate them as a single escalation path in which the short-term obligation's penalty sits below the consequences that apply once a conservation campaign and customer compensation are triggered.

Duplication with the LNG facility and the Huntly reserve

The LNG import facility and the 600,000-tonne Huntly coal reserve both target fuel availability, which is the very gap the short-term obligation is intended to address. We accept the point that the short-term obligation is, in part, the mechanism that requires generators to procure, contract for and hold fuel through arrangements such as these, so it is not simply redundant.

The risk ERGANZ is concerned with is narrower, that the obligation compels members to secure, and consumers to pay for, additional cover on top of what the Huntly reserve already delivers and an LNG facility would deliver once operational, and to do so before the long-term obligation has had any opportunity to work. Where the long-term obligation has already prompted the necessary investment and contracting, a further short-term requirement may add cost without adding reliability.

The question is therefore one of *residual gap*. ERGANZ asks officials to identify, with analysis, what reliability gap remains once the LNG facility and the Huntly Strategic Energy Reserve are in place and the long-term obligation is operating, and to size the short-term obligation to that residual gap alone. The regime should be designed so that cover secured through Huntly-related arrangements or LNG procurement is fully creditable and not double-counted or double-charged.

> **Recommendation 6**
> MBIE should quantify the residual reliability gap that remains after the LNG facility, the Huntly Strategic Energy Reserve and the long-term obligation are in place, size the short-term obligation to that residual gap, and ensure cover already secured through those arrangements is fully creditable against it.

Additional submission points

Penalty calibration

MBIE states an intention to "tilt" rather than "force" investment (paragraph 92 and Table 3), however, a penalty set at the greater of $10 million, three times commercial gain, or 10 percent of turnover is significant. It risks becoming the dominant factor in investment decisions rather than a marginal one. This tips the regime from "tilt" into "force", driving inefficient over-procurement whose cost, as the paper concedes (paragraph 91), flows through to consumers.

Show the cost-benefit working

The consultation paper presents the price effects of the obligations as essentially one-directional: reduced dry-year peaks and volatility flowing through to lower prices. In reality the picture is two-sided. Dry-year peaks and volatility should indeed fall, but average and baseline prices are likely to rise to fund the standing cost of the cover the obligation compels, a cost incurred every year whether or not a dry year eventuates.

Whether this policy proposal is a good deal for consumers depends entirely on how much cover is required, which is a sizing question the paper does not answer.

The asymmetric-cost argument at paragraph 37, that the cost of shortfalls exceeds the cost of surplus, is asserted rather than calculated. ERGANZ asks MBIE to show its working: the assumed Value of Lost Load, how the efficient quantity of cover is derived from it, and the point at which additional cover tips into over-procurement that consumers pay for in every normal year.

Without this analysis, the net consumer benefit that is the entire justification for the regime has not been established. Concept's report (Appendix A) provides system-cost modelling directly relevant to this question, including the declining thermal-need trajectory noted in the executive summary and an estimate that the obligations as proposed would raise the average wholesale component of consumer prices by around $15 to $50 per MWh, or roughly 13 to 42 percent, with sensitivity to the penalty level and to fuel costs. We note that Concept quantifies the cost of the obligation but, like the paper, does not derive the offsetting consumer benefit, which reinforces the need for the analysis sought here. We recommend Concept’s report to officials.

Recommendation 7
The Government should take the time to properly assess and publish the costs and benefits of the proposal, and engage further with industry, before any decision to proceed. To that end, MBIE should undertake and publish a quantified cost-benefit analysis that demonstrates a positive net consumer benefit, showing the assumed Value of Lost Load, the derivation of the efficient quantity of cover, and the standing annual cost to consumers across normal years.

Conclusion

ERGANZ thanks the Ministry for the opportunity to comment on these proposals and for considering our submission.

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

Yours sincerely,

Kenny Clark
Policy Consultant