WERO Discussion Document — Summary Addendum

The WERO discussion document has the makings of the machinery the country needs to solve dry year risk, reduce wholesale prices, and operating with much more solar and wind, balanced by BESS —sized off the SOSA. Our feedback focuses on unlocking benefits through ensuring **long-term contracts for new generation**, **competitive procurement through auctions, technology-neutrality**, and **including energy and capacity margins to reflect the SOSA / Transpower pipeline.**

Set the procurement quantities from the SOSA

- **Convert the SOSA's own staging into the auction quantity.** MBIE's note on the non-availability of long term forward contracts is exactly right. The primary way to tackle dry year risk is ensuring projects in Transpower's queue (reflected in the SOSA) get financed and built. Without this certainty, a significant quantity of the energy supply pipeline (GWh) will simply move around from year to year—for example, the SOSA forecast for 2031 had 5,000 less GWh in the 2026 edition, compared with 2025.
- **Contract the Stage 2 + Stage 3 gap, capped.** Stage 2 projects are consented but still not committed (no FID) — the clearest sign the constraint is revenue certainty, not planning. Stage 3 projects have inherent uncertainty / risk as they are unconsented. Contracting is the best way to bring certainty. Fix with a rolling multi-year procurement schedule, capped to remove the risk of over procurement.
- **Require obligated parties to procure the quantity, split between gentailers and large load customers.** Through a standardised competitive process (e.g. auction) overseen and enforced by the EA.

Dry year needs to be looked at from an annualised, whole-of-system basis

- **Assess security of supply annualised, not through a winter lens.** Solar and wind overproduction during summer and autumn displaces hydro (long duration storage) and leaves more water in the lakes going into winter — that stored water is winter firm energy. Model hydro displacement explicitly when setting the WERO quantity, or the shortfall is mis-sized and the cover mis-priced.
- **Free hydro for its highest-value role.** Conscripting it into frequency keeping and contingent reserves ties up capacity whose best use is long-duration seasonal and dry-year storage — BESS performs ancillary services closer to the load and faster.

Target both SOSA margins — energy and capacity

- **The WERO should consider energy and capacity margins.** Transpower's / SOSA pipeline is almost entirely intermittent solar and wind, which adds energy without adding firming capacity or ancillary support — these functions provided by BESS are essential, and we believe are being missed.
- **Assess both margins, and procure against each.** Size the SOSA on energy and capacity and define auction products that cover both.

Qualifying cover

- **Define products by the response required — speed, magnitude, duration.** Not continuous MW over a dry period – there is almost no new generation that will qualify or get built, and risks market distortion.
- **Recognise battery + hydro pairing.** Batteries (short duration) take the daily peaks so hydro (long duration) holds water going into and during, winter.

Tenor and protection against existing generation

- **New-build gets long tenor.** 20-year contracts let lenders size debt against contracted cashflows and unlock capital – projects get built. This alone will solve dry year risk and bring wholesale prices down.
- **Existing plant gets one-year agreements (UK model); require bid bonds.** No windfall for capacity already built (the SOSA may solve for this?) And security guards against attrition.

Additional point: Frequency and ancillary services

- **Look into Part 8 AOPO that conscripts every large generator into frequency keeping and reserves.** Procure those services competitively through the market instead. There is a real need for the EA / Transpower to reform the ancillary services market to reflect our changing generation mix.

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Consultation submission form

The Ministry of Business, Innovation and Employment (MBIE) would like your feedback on:

A proposed reliability obligation to manage dry-year risk.

Please provide your feedback by **5pm, 21 July 2026**

When completing this submission form, please provide comments and supporting explanations for your reasoning where relevant. Your feedback provides valuable information and informs decisions about the proposals.

We appreciate your time and effort taken to respond to this consultation.

Instructions

To make a submission you will need to:

1. Fill out your name, email address, phone number and organisation. If you are representing an organisation, please provide a brief description of your organisation and its aims, and ensure you have the authority to represent its views.
2. Fill out your responses to the discussion document questions. Where possible, please provide us with evidence to support your views. Examples can include references to independent research or facts and figures.
3. If your submission has any confidential information:
    i. Please state this in the email accompanying your submission, and set out clearly which parts you consider should be withheld and the grounds under the Official Information Act 1982 (Official Information Act) that you believe apply. MBIE will take such declarations into account and will consult with submitters when responding to requests under the Official Information Act.
    ii. Indicate this on the front of your submission (e.g. the first page header may state "In Confidence"). Any confidential information should be clearly marked within the text of your submission (preferably as Microsoft Word comments).
    iii. Note that submissions are subject to the Official Information Act and may, therefore, be released in part or full. The Privacy Act 1993 also applies.
4. Submit your feedback:
    i. By email to *electricitymarkets@mbie.govt.nz*
    ii. By mailing your submission to:

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

Submitter information

MBIE would appreciate if you would provide some information about yourself. If you choose to provide information in the section below, it will be used to help MBIE understand how different sectors view the proposals and options for requiring and achieving minimum onshore fuel stockholding. Any information you provide will be stored securely.

Your name, email address, phone number and organisation

Name:	Paul Burnaby
Email address:	Privacy of natural persons
Phone number:	
Organisation:	Pacific Power Resources

☐ The Privacy Act 1993 applies to submissions. Please tick the box if you do **not** wish your name or other personal information to be included in any information about submissions that MBIE may publish.

☐ MBIE may upload submissions and potentially a summary of submissions to its website, www.mbie.govt.nz. If you do **not** want your submission or a summary of your submission to be placed on either of these websites, please tick the box and type an explanation below:

I do not want my submission placed on MBIE's website because... [insert reasoning here]

Please check if your submission contains confidential information

☐ I would like my submission (or identifiable parts of my submission) to be kept confidential, and **have stated** my reasons and ground under section 9 of the Official Information Act that I believe apply, for consideration by MBIE.

Questions for the consultation

Q1. Do you agree with the analysis in this chapter of why New Zealand does not currently have sufficient dry-year firming? If not, where do you disagree?

☐ Yes ☒ Yes, with changes ☐ No

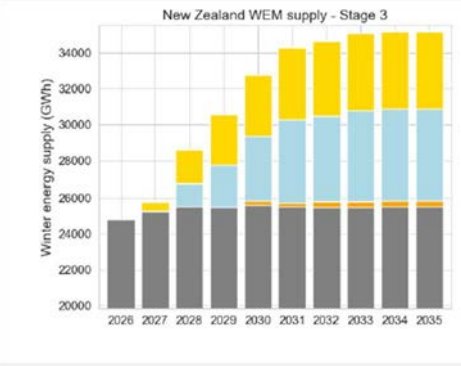
Please explain your views.

We mostly agree with the analysis. The 'tenor gap' — contracts of 10–15 years or more (we suggest 20 years) are needed for any generation to recover costs, but buyers will not commit that long — and the resulting financing constraint are exactly what limits new generation being built.

Gentailers, the main source of long term contracts in NZ, use their market position and act rationally – profit maximising and thus deciding what gets built through contracts and/or JVs; and internal projects financed on balance sheet. Forward contracts of up to 3-4 years tenor traded on the ASX are too short to finance plant for merchant generation projects. The 2026 SOSA independently confirms the outcome: an emerging dry-year energy gap, with the New Zealand Winter Energy Margin falling below the lower security standard by 2031 'even with all committed and likely investments delivered without delay' – a highly unlikely scenario given Stage 2 and Stage 3 projects either are unconsented or haven't yet reached the Financial Investment Decision (FID).

We suggest two changes to the analysis that will be reflected through our submission. First, dry-year risk is driven by not enough new generation being built, regardless of the type of generation or the time of year - as such any WERO obligation should be assessed on an annualised, whole-of-system basis, not through a winter lens. The key insight is solar and wind production in spring / summer / autumn displaces hydro — the system's long-duration storage — and leaves more water in the lakes going into winter. That stored water is winter firm energy, and if hydro displacement is not modelled explicitly when setting the obligation quantity, the shortfall is mis-sized and the cover mis-priced. In addition to wind and solar, the more resources such as BESS that are brought online performing peaking and ancillary functions, the more water is available for seasonal storage. This reflects the significant structural change we are seeing in generation mix and the resultant operation of NZ's power system.

Second, the analysis – and WERO obligation - should target both SOSA margins — energy and capacity – as these are reliant on each other. The 2026 SOSA describes a pipeline 'heavily weighted towards wind and solar' — intermittent, inverter-based generation that adds energy without adding dependable capacity — and separately flags capacity risk 'during cold, dark, still winter mornings and evenings.' A system can pass an energy test and still fall short of megawatts at peak. Additional ancillary services and capable plant, such as BESS, is required to unlock the wind and solar pipeline. The following Figure 3 from the 2026 SOSA illustrates how solar (yellow) and wind (blue) make up almost the entire pipeline (grey being existing generation).



Q2. What do you consider to be the principal remaining barriers to investment in additional dry-year firming following the recent reforms to improve fuel adequacy (Government procurement of an LNG importation facility)?

Please explain your views.

Revenue certainty is the principal remaining barrier — not planning, and not fuel. And not through lack of project opportunities (the Transpower connection pipeline contains over 20GW of potential generation plant.) Stage 2 projects in the SOSA's staging are consented but still uncommitted: the clearest possible evidence that the binding constraint is the absence of long-dated revenue contracts rather than consenting (which has been and continues to be addressed). The discussion document concedes the mechanism— better information and accountability 'do not create bankable revenues for long-duration firming' — and lenders size debt against contracted cashflows, not against the possibility of being contracted in a dry year.

The 2026 SOSA shows what an uncontracted pipeline does in practice: projects' online date shift into the future. Some projects committed in the 2025 assessment for 2027 delivery have been 'pushed back a year and/or are now classified as uncommitted'; some large wind projects were simply not re-disclosed by investors in this year's survey; and the new 75% likelihood screen removed a further tranche of projects previously counted as prospective supply – this will continue to move around as long as long term contracts are difficult to obtain. On our analysis of the SOSA's year-on-year comparison, the 2031 supply outlook lost roughly 5,000 GWh between the 2025 and 2026 editions. Without contracts, forecast supply simply migrates from one assessment to the next while the 2031 gap approaches.

The LNG facility addresses fuel adequacy for existing thermal plant. It does not create a bankable revenue stream for new firming resource — the contracting barrier remains untouched.

Q3. Do you agree that, despite the recent reforms to improve fuel adequacy, information, roles and tools, further measures are still needed to strengthen incentives to invest in dry-year firming? If not, please explain why not?

☒ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

Yes. The document makes the case in its own words: the recent reforms strengthen information, roles and tools, but they 'do not create bankable revenues for long-duration firming.' The System Operator reaches the same conclusion from the other direction — the 2026 SOSA warns that falling generation-weighted prices are already increasing the risk of pipeline projects 'being delayed or cancelled.' – exactly what happens in an energy-only market with uncontracted (merchant) pipeline. The measure still needed is the one that delivers the document's own stated goal of closing the revenue-certainty gap: long-term contracts for new generation, competitively procured, technology-neutral (defined by speed, magnitude, and duration), and quantity assessed against both the SOSA energy and capacity margins.

Q4. Do you agree that there is value in building new measures on existing regulatory architecture, rather than creating an entirely new regime from first principles? Why or why not?

☒ Yes, I agree ☐ No, I don't agree

Please explain your views.

Yes. The machinery already exists and should be used and otherwise risks market distortions. The SOSA already produces a staged, likelihood-screened assessment of the pipeline against defined security standards; converting that staging into the procurement quantity means the assessment

already goes a long way to setting the annual contract quantity. The additional steps of working through a rolling multi-year procurement schedule with a capped quantity (to remove the risk of over procurement) are the additional steps required.

We would also encourage MBIE to revisit the Australian precedents referenced in the discussion document. The NSW LTESA and federal Capacity Investment Scheme were cited as arguments against a contracting mechanism, but they are the reason Australia now finances grid-scale batteries and long-duration firming at pace while New Zealand does not. Our proposal takes the proven element of those schemes — a standardised, competitively awarded long-term contract — in a materially lighter form: obligated wholesale purchasers, not the Crown, are the counterparties, so there is no government balance sheet exposure and no Crown "standing in the market." The existing regulatory architecture (SOSA sizing, EA rule-making) supplies everything else.

Long-term Obligation

Q5. Do you agree that a long-term obligation should be introduced to strengthen incentives to secure sufficient dependable winter cover in advance where a forecast winter energy adequacy shortfall is identified? If not, why not?

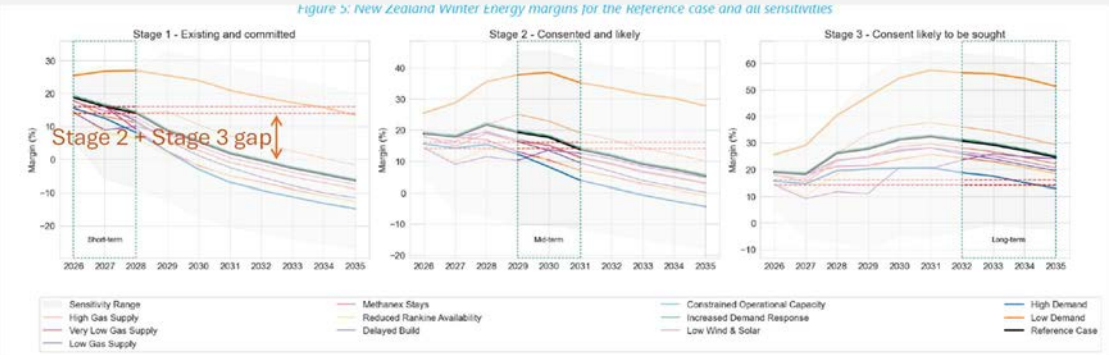
☒ Yes, I agree ☐ No, I don't agree

Please explain your views.

Yes — we endorse the long-term obligation. A quantity target, sized off the SOSA, is exactly the machinery the market needs, and the five-year horizon is long enough to build against.

But the obligation will fail its own stated goal unless it produces long-term contracts that finance new generation. As drafted, a duty that switches on and off with the forecast steers obligated buyers toward the shortest, cheapest cover that satisfies that year's assessment — sourced from existing plant, largely their own. That manufactures compliance without building anything, and it reproduces precisely the tenor gap the discussion document identifies.

The completing piece is competitive procurement: government sets the quantity through the SOSA based on Stage 2 + Stage 3 gap in the energy and capacity margins with a capped quantity (to remove the risk of over procurement); competition sets the price (for example, a standardised auction designed by the EA, open to all technologies.) Figure 5. From the 2026 SOSA (shown below) details what we mean by the Stage 2 + Stage 3 gap.



We agree with the discussion documents direction that the procurement quantity is then split among large wholesale purchases – obligated parties – with the EA ensuring the obligated parties run a competitive procurement process. No government backstop required.

Also, to repeat what we stated in Q1: dry-year risk is driven by not enough generation able to be built, regardless of the time of year - as such any WERO obligation should be assessed on an annualised, whole-of-system basis, not through a winter lens. Solar and wind production in spring / summer / autumn displaces hydro — the system's long-duration storage — and leaves more water in the lakes going into winter. That stored water is winter firm energy, and needs to be modelled explicitly. This reflects the changing operation of NZ's energy system with intermittent generation.

Q6. Do you agree that the long-term obligation should be placed on large wholesale purchasers rather than on, say, generators or the market more broadly? If not, which parties should hold the obligation, and why?

☒ Yes, I agree ☐ No, I don't agree

Please explain your views.

Yes. Large wholesale purchasers are the right obligated parties — they assemble the portfolio of supply and contractual cover, and placing the duty on them keeps the Crown out of the market entirely. The four vertically integrated players control roughly 85% of generation and retail.

Two refinements. The obligation should sit on gentailers and large load customers, with the total procurement split between them. And obligated parties should be required to procure through a standardised competitive auction (or other such competitive mechanism) — overseen and enforced by the EA — rather than through bilateral arrangements negotiated where they are able to exert market power.

Q7. Do you agree that a de minimis threshold should apply to limit the obligation to wholesale purchasers with a material winter load? If so, is the 500 GWh threshold appropriate, and should it be measured by reference to aggregate load over the winter period?

☐ Yes, I agree ☒ I agree in part ☐ No, I don't agree

Please explain your views.

We agree in part. A de minimis threshold is sensible and 500 GWh of aggregate winter load is a workable starting point, provided the regime includes rules so load cannot be split across related entities to dodge the threshold.

We would note that the threshold matters far less than the qualification rules: what counts as qualifying cover (Q10) is the design choice that determines whether the obligation brings on new resources or is met by shuffling existing plant.

Q8. Do you agree with the proposed staged approach under which a warning notification would be issued five years out, a binding obligation would be issued three years out and compliance would be assessed one year out? If not, what timing or trigger approach would be preferable?

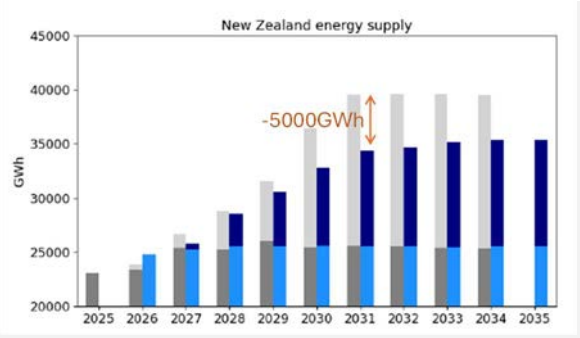
☐ Yes, I agree ☐ I agree in part ☒ No, I don't agree

Please explain your views.

The approach introduces uncertainty, which is unbankable and will not result in the financing and construction of new generation. How do you contract a 30 year asset if it's revenue can turn on and off based on the weather?

The final approach needs to reflect the critical path for building new generation which is set by the Transpower connection pipeline – for grid connected projects. Typically, this is a about a 4-5 year timeframe but does shift around depending on Transpower's internal resource and the required connection works (per a Transpower Works Agreement.) There are of course projects already in the pipeline that could come on-line sooner if they were contracted. So, on balance between 4-5 years makes sense.

An additional (important) complication is what happens between SOSAs and how this affects the staged approach. The 2026 SOSA's own record shows how much the quantities move: projects committed in last year's assessment have been pushed back or reclassified as uncommitted; large wind projects were not re-disclosed; and the new 75% likelihood screen removed a further tranche — on our analysis, roughly 5,000 GWh out of the 2031 outlook. An obligation whose quantity appears and vanishes with each annual assessment will be met with short-dated cover, because no one finances new plant against a duty that may not exist next year. We'd expect to see this dynamic continue as long as projects remain uncontracted. Figure 4 showing committed and planned supply from the 2026 SOSA illustrates the point – the grey bars are from 2025 SOSA and the blue bars from 2026 SOSA.



We suggest a rolling, multi-year procurement schedule with a capped quantity, contracting the Stage 2 + Stage 3 gap. The SOSA itself points here: it describes Stage 2 — consented projects likely to proceed but not yet reached FID and observes that bringing Stage 3 projects forward ahead of 2031 carries higher delivery risk because they are unconsented and uncontracted.

Q9. Do you agree that any identified adequacy shortfall should be allocated among obligated wholesale purchasers by reference to their shares of expected winter demand? If not, what allocation approach would be preferable?

☒ Yes, I agree ☐ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

Allocation by shares of expected winter demand is simple, proportionate and hard to game.

The more important question sits upstream: the quantity being allocated should be based on the SOSA Stage 2 + Stage 3 gap (with a cap to prevent over procurement); and should be calculated on an annualised, whole-of-system basis with hydro displacement explicitly modelled, and should be assessed against both the energy and capacity margins. This will ensure the obligation reflects the lowest LCOE generation, Transpower's actual pipeline, and ensures system security and ancillary services continue to be supported.

Q10. What forms of cover should be eligible to meet the long-term obligation?

Please explain your views.

This is an important design choice. Qualifying cover should be defined by the response the system requires — **speed, magnitude and duration** — and not as thermal-shaped continuous MW across a dry period. It should recognise that any new generation improves dry year risk directly, and indirectly through displacing hydro as long-duration storage – which is winter firm energy.

As an example of what wouldn't work: A thermal-shaped specification could exclude almost every resource in the current SOSA / Transpower pipeline (solar and wind) from qualifying, however large the obligation, and would distort the market toward incumbent plant or plant that doesn't exist in the pipeline. Procurement of new generation would be difficult.

To make "duration" workable in contractual terms, it should be defined at the product level, not the asset level. An asset-level test (hours of continuous output at rated capacity) would exclude nearly every resource in the actual consenting and connection pipeline. A product-level definition — a contracted quantity of GWh deliverable across the assessment window, plus MW available within defined peak windows, verified by metering — tests what the system actually needs and lets all technologies compete. We suggest the regime adopt duration classes (as UK and Australian capacity mechanisms do) rather than a single continuous-output threshold: per-event duration (sustained output when called) and seasonal duration (total GWh across the window) are

distinct products and should be specified and procured as such. A battery cycling daily delivers modest per-event duration but material seasonal energy; paired with hydro it delivers both.

Complementary pairings should therefore be contractible as a single portfolio product, with compliance credit assigned by the contract itself. This also resolves the attribution and double-counting questions raised in Question 11 before they arise: credit follows the contractual entitlement, not an inference about physical flows.

Finally, the market has already shown what happens when qualifying cover defaults to existing plant. The Commerce Commission-authorised ten-year arrangement to keep the Huntly Rankine units available into the 2030s demonstrates two things: long-term firming contracts are workable under existing law, and absent well-designed qualification rules, the obligation will be met by extending the life of legacy thermal plant rather than by building anything new. The qualification rules are the design choice that determines which of those futures WERO delivers.

The WERO should consider **SOSA energy and capacity margins** as the pipeline is almost entirely intermittent solar and wind, which adds energy without adding firming capacity or ancillary support — these functions provided by BESS (or any other able plant) are essential, and we believe are being missed in the document. We think this risk is not adequately being considered by the EA given NZ's current limited installed capacity of solar – however, this is changing rapidly and similar markets with high solar penetration (AEMO, CAISO, ERCOT) should provide a strong indication of what will be required in NZ.

Defining products by outcome is consistent with the document's own framing that the regime should focus on whether arrangements 'credibly improve the system's ability to maintain supply,' rather than prescribe a technology.

Qualifying cover should also recognise complementary pairings, because the whole-of-system effect is larger than either resource alone. The SOSA notes that batteries manage peaks but 'do not contribute additional energy' — correct in isolation, but incomplete: short-duration storage taking the daily peaks allows hydro, the system's long-duration store, to hold water going into and through winter.

Q11. How should the compliance framework be designed? In particular, what evidential standard should apply, and how should the regime address more difficult issues such as hydro treatment, attribution, portfolio treatment, shared arrangements and double counting?

Please explain your views.

Defining a standardised mix of products that address the SOSA energy and capacity margins—clear qualification, delivery and verification terms —hold the product and you are compliant. Explicit contractual entitlements collapse most attribution, portfolio-treatment and double-counting questions that arise when compliance is inferred from portfolios.

On hydro treatment: assess it annualised and whole-of-system. Stored water accumulated through summer displacement is genuine winter cover and should count as such; equally, conscripting hydro into peaking and ancillary services ties up capability whose highest-value role is seasonal storage.

Q12. Should the regime deal with arrangements that appear compliant in advance but later fail because of counterparty failure, project delay, force majeure or similar events? If so, how?

☒ Yes, I agree ☐ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

Yes. Large wholesale purchasers, as part of running an auction of capacity and energy, should evaluate projects based on both price and likelihood of meeting their online dates and performance requirements. Those purchasers are likely to over procure to ensure they meet their minimum requirements, knowing some projects may fail.

Bidders into the auction should be required to post performance security at the point cover is secured: bid bonds and performance guarantees for contracted new-build, with creditworthiness standards on counterparties. Where cover fails, the primary remedy should be a prompt re-procurement obligation on the affected purchaser, with the penalty regime only as a back-stop: the system needs the megawatt-hours, not the fine.

These protections are standard practice in comparable markets. Storage tolling agreements in the United States and Australia routinely include availability-based liquidated damages, capacity testing regimes, and parent-company or bank guarantees — and battery projects are among the easiest resources to verify against them, being metered, routinely performance-tested, and free of upstream fuel-supply or transport risk. By contrast, cover reliant on fuel logistics carries precisely the failure modes this question identifies (upstream supply failure, transport disruption), which argues for the compliance regime valuing resources whose deliverability can be demonstrated in advance rather than assumed.

Q13. Should penalties for non-compliance be designed and calibrated to tilt investments to comply without overly encouraging inefficient over-procurement? Please explain your reasoning.

☒ Yes, I agree ☐ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

The shortfall charge must sit above the expected cost of a long-dated contract for equivalent cover. If paying the penalty is cheaper than contracting, obligated parties will rationally pay it and re-shuffle existing plant. The charge should be indexed to observed contract prices — this is one benefit of an auction which provides a published benchmark.

Penalties should explicitly fine the bonuses of executive compensation of Large Wholesale Purchasers who are non-compliant. Incentives drive decisions.

We agree with the document's description: the economic and social costs of a shortfall are significantly greater than the cost of a modest surplus, scarcity has economy-wide impacts, and access to firming has dynamic benefits for renewable investment and competition. The security standards themselves (a 14–16% band for WEM) are already based on an efficient level of investment (e.g. not guaranteeing a dry year won't occur) which further reduces the risk of over-procurement. The genuinely expensive outcome is the current one: emergency procurement in dry years and a scarcity premium priced into every retail contract.

Q14. What other design features, transitional arrangements, or implementation issues should be considered to ensure that the long-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

Please explain your views.

We have detailed throughout our response the design features that will ensure the WERO will materially solve dry year risk, reduce wholesale prices, and enable system security and resource adequacy with much more solar and wind, balanced by BESS —sized off the SOSA.

The single most important completing feature is the procurement mechanism: a standardised long-term contract, qualifying cover defined around outcomes, competitively

procured (e.g. auctioned), with obligated purchasers as counterparties. Tenor should differentiate new-build from existing plant: long tenor (20 years) for new resources, which lets lenders size debt against contracted cashflows and unlocks capital; one-year agreements for existing plant, so there is no windfall for capacity already built.

Ancillary services reform should proceed alongside the obligation reflecting the changing generation mix in NZ. The Part 8 arrangements that conscript every large synchronised generator into frequency keeping and reserves should be reviewed so those services are procured competitively — freeing hydro for its highest-value role as the system's long-duration storage. The SOSA's findings reinforce the point: usable HVDC transfer already depends on the availability of instantaneous reserves, and an increasingly inverter-based, wind-and-solar-dominated system will make system services a binding constraint. Procuring them competitively is the same logic as the obligation itself: define the product, and pay whoever delivers it cheapest.

Finally, timing. The SOSA's short-term recommendation is that industry deliver new generation and batteries on time; its mid-term finding is a 2031 breach even if everything currently likely is built. Working back from 2031 through consenting, connection and construction, the first procurement rounds need to run well before the first binding obligation notification. We recommend the architecture be designed now, in parallel with the legislation, and we would welcome the opportunity to work with MBIE on product design.

Short-term Obligation

Q15. Do you support the introduction of a short-term obligation as a targeted backstop where a near-term winter reliability risk emerges despite the operation of the long-term obligation?

☐ Yes, I agree ☐ No, I don't agree

Please explain your views.

It's a reasonable idea in theory, but the question becomes timing for delivery, as we think dry year risk can be largely solved in a few years from the time the long term mechanism is implemented as we suggest – providing long term contracts for new generation and BESS. Thus, if it takes more than a few years to deliver the short-term obligation then it risks becoming redundant.

The long term mechanism is much more important for solving dry year risk cost effectively, so any short-term obligation needs to be carefully designed to not distort the market in such a way that will discourage the long-term obligation and incentives to invest in new generation.

If our recommendations in the long-term obligation were implemented, we'd expect sufficient GWh to be on the system within a few years such that the short term obligation may no longer be necessary. As such we have focused our submission on shaping the long-term obligation as we consider this to be the key for solving dry year risk.

Q16. Do you agree that the short-term obligation should apply to large generators whose contribution to annual energy supply exceeds a defined *de minimis* threshold? We welcome views on whether 2,500GWh of expected annual generation is the appropriate threshold.

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q17. Do you consider the proposed trigger – projected hydro storage crossing the Watch Curve within 90 days if it declines at an assumed rate of 18GWh/day – is appropriate? If not, what alternative trigger should be considered?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q18. Do you agree with the proposed monitoring period, notification process, three-week response window, and approach to switching off the obligation if conditions improve? If not, what alternative process would be preferable?

☐ Yes, I agree ☐ No, I don't agree

Please explain your views.

[insert response here]

Q19. Do you agree that each obligated generator's obligation should be determined by reference to the winter load its portfolio is expected to support, including its own retail load and relevant contractual commitments? If not, what alternative basis should be used?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q20. What forms of firm energy fuel cover should qualify under the short-term obligation? In particular, how should hydro be treated, including whether, and in what circumstances, existing stored water should be capable of counting toward compliance?

Please explain your views.

[insert response here]

Q21. How should compliance be assessed? We welcome views on what evidence should be required, and how the Authority should approach questions of firmness, attribution, double counting, and reliance on third-party arrangements (including examples of how these matters are addressed in other jurisdictions).

Please explain your views.

[insert response here]

Q22. How should the regime deal with arrangements that appear compliant in advance but fail in practice because of upstream supply failure, transport disruption, force majeure, counterparty failure, or similar events?

Please explain your views.

[insert response here]

Q23. How should penalties for non-compliance be designed and calibrated so that they provide a credible incentive to secure genuine firm fuel cover without encouraging inefficient or disproportionate responses?

Please explain your views.

[insert response here]

Q24. What other design features, transitional arrangements, or implementation issues should be considered to ensure that the short-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

Please explain your views.

[insert response here]